MACKENZIE VALLEY PIPELINE INQUIRY

IN THE MATTER OF AN APPLICATION BY CANADIAN ARCTIC GAS PIPELINE LIMITED FOR A RIGHT-OF-WAY THAT MIGHT BE GRANTED ACROSS CROWN LANDS WITHIN THE YUKON TERRITORY AND THE NORTHWEST TERRITORIES FOR THE PURPOSE OF THE PROPOSED MACKENZIE VALLEY PIPELINE

and

IN THE MATTER OF THE SOCIAL, ENVIRONMENTAL AND ECONOMIC IMPACT REGIONALLY OF THE CONSTRUCTION, OPERATION AND SUBSEQUENT ABANDONMENT OF THE ABOVE PROPOSED PIPELINE

(Before the Honourable Mr. Justice Berger, Commissioner)

Yellowknife, N.W.T.

April 14, 1975.

PROCEEDINGS AT INQUIRY

VOLUME XXIX

APPEARANCES:

Mr. Ian G. Scott, Q.C. Mr. Stephen T. Goudge, Mr. Alick Ryder and Mr. Ian Roland	for Mackenzie Valley Pipeline Inquiry;
Mr. Pierre Genest, Q.C. Mr. Jack Marshall, Mr. Darryl Carter and Mr. John Steeves	for Canadian Arctic Gas Pipeline Limited;
Mr. Reginald Gibbs, Q.C. Mr. Alan Hollingworth	for Foothills Pipelines Ltd.;
Mr. Russell Anthony, and Prof. Alastair Lucas	for Canadian Arctic Resources Committee;
Mr. Glen W. Bell and Mr. Gerry Sutton	For Northwest Territories Indian Brotherhood and Metis Association of the Northwest Territories;
Miss Lesley Lane	for Inuit Tapirisat of Canada and The Committee for Original Peoples' Entitlement;
Mr. Ron Veale and Mr. Allen Lueck,	for Council for Yukon Indians
Mr. Carson H. Templeton,	for Environm ental Protection Board;
Mr. David Reesor,	for Northwest Territories Association of Municipalities;
Mr. Murray Sigler,	for Northwest Territories Chamber of Commerce.

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Yellowknife, N.W.T.
April 14, 1975.

(PROCEEDINGS RESUMED PURSUANT TO ADJOURNMENT)

MR. SCOTT: Mr. Commissioner, I thought I should outline what I've discussed with my friends with respect to the timetable for this week. I anticipate that we will be able, everyone will be delighted to hear, to excuse this panel sometime this afternoon, and begin with the next panel, four members of which are here. The balance will be coming in on the three o'clock plane and Mr. Marshall suggested that if necessary, not to waste any time, we can begin with the panel of four and supplement it as the transportation permits.

Then we will continue tomorrow with that panel in chief and I propose, and I think my friends agree, that if it's not finished by one we should continue in the afternoon until it is finished.

Then we will have Mr. Gibbs free energy on Wednesday, and I would propose that we should continue as a matter of personal conven-ience to him, because he has other obligations, either to one or until later in the day or whatever time is required to enable him to finish his cross-examination.

With that in mind, I would therefore propose that the motion that was going to be argued tomorrow at two o'clock should be instead argued on Thursday at two o'clock. I'll let Mr. Veale know that, and I anticipate it will not

inconvenience anybody who is here.

MR. MARSHALL: Mr. Commissioner, before my friend begins his cross-examination again, there were a number of undertakings that we are able to respond to now, and perhaps those could go into the record.

The first was directed to Dr. Cooper on April 11th, and can be found at page 3500 of the transcript, and it pertained to calculating the statistical range within which the 100-year flood estimate would fall, and Dr. Cooper can respond to that now.

WITNESS COOPER: Mr. Commissioner, I have a slide here that is a plot flood frequency curve with confidence limits on it, and with your permission I'll show it.

This is a plot of a flood frequency curve of the Mackenzie River at Norman Wells. What it plots is the maximum annual discharge, the maximum annual flood discharge against the frequency of recurrence of that discharge. As you see, we have 24 points. This was based on 24 years of record. I believe this takes us up to the end of 1971 or '72. There are several more points now.

The blue line that you see is the best fit curve for a log normal distribution of these data. Now the best estimate of the 100 year flood, you'll notice that the scale down here is, instead of being expressed in terms of frequency, it's expressed in terms of the return period for

the year. For example, the one and two-year flood
would be this value.
would be this flood. The one in 100 year flood would be this value. The point on the blue line is the best estimate based on these data. Now the two green curves are the 95% confidence limits which means statistically speaking we have 95% confidence that the estimate for a 100 year flood will fall between this value and this value. In this case it's between 940,000 cubic feet per second and 1,400,000 approximately, cubic feet per second. The best estimate here is 1,100,000.

Now the reason that I say that I feel this record is adequate is because we can examine even the value up here, and it will make very little difference to our scour computation. I did a rough computation on this, and it would affect the scour elevation by something in the order of one foot. Is that the --

MR.SCOTT: Can you just express for us, to be sure we have them then, the difference in volumes of discharge between the two green lines?

WITNESS COOPER: 940,000 cubic feet per second here, and 1,400,000 cubic feet per second. The best estimate would be 1,100,000.

MR. SCOTT: And that gives you, in your judgment, a confidence level of 95%?

WITNESS COOPER: Yes.

MR. MARSHALL: Mr. Commissioner, I would suggest that that graph be entered as the next

exhibit, which I understand is 97.

(GRAPH MARKED EXHIBIT 97)

MR. MARSHALL: The next undertakings were with respect to Dr. Sluaarchuk's evidence on April 9th at 3261 in the transcript, he was asked to provide data on the heave of gauge pairs at the Calgary field test facility. He has put together a collection of data that provides information with respect to heave at the test-site, and I'd like to enter a copy of that as the next exhibit.

(HEAVE AT CALGARY TEST-SITE MARKED EXHIBIT 98)

On April 10th, Dr. Slusarchuk was asked at 3419 in the transcript, to identify the passages in the Battell report entitled "A convective Model for Sub-Surface Flow Around a Chilled Pipeline", dated October the 31st, 1974, that dealt with the effect of sub-surface flow on the freeze zone surrounding a chilled pipeline.

Dr. Slusarchuk has reviewed the report and the references are found at pages 2439 and 40. Unless Mr. Scott requires, we don't intend to read those into the record.

Mr. Williams had been asked on March 21st at 2755 in the transcript, for the locations where blasting may be required. I would like Mr. Williams to respond to that undertaking.

MR. WILLIAMS: Yes, I think that the table that Mr. Marshall is entering is self-evident. It gives the -- a summary of estimated blasting requirements by terrain units in five physiographic divisions. There will probably be some discussion with respect to this in the construction panel, and I would suggest maybe we leave further discussion of that until then.

MR. MARSHALL: Mr. Commissioner, Mr. Williams has prepared such a one sheet summary entitled "Prime Route with Fort Simpson" and then summary of terrain units and miles and estimated blasting requirements. I would like to enter that as the next exhibit.

(ONE SHEET SUMMARY ENTITLED "PRIME ROUTE WITH FORT SIMPSON" MARKED EXHIBIT 99)

On April 10th at page 3297 of the transcript, Mr. Williams was asked to advise as to what report the drawing of the Sans Sault site came with. Mr. Williams, can you respond to that please?

MR. WILLIAMS: Yes, this sketch of the Sans Sault site that Mr. Scott asked about the details of five subdivisions at the site, was included in a letter from Dr. Mollard to Harold L. Morrison of R.M. Hardy and Associates on February the 6th, 1970, with a copy to Mr.Dau of -- at that time, Williams Brothers Canada Limited.

I managed to find this in our files and don't really classify it as a report, Mr. Scott.

MR. MARSHALL: Mr. Scott, we proposed to enter that as an exhibit, the letter with the attached sketches.

(J.D. MOLLARD AND ASSOCIATES LETTER OF FEBRUARY 6, 1970 MARKED AS EXHIBIT 100)

MR. MARSHALL: On April the 10th, at 3302 to 05 of the transcript, Mr. Williams was asked by Mr. Anthony for clarification concerning the selection of these six potential sites that Dr. Mollard had selected.

MR. WILLIAMS: Yes, I think in the transcript I referred to five potential sites that Dr. Mollard had selected for further investigation. In digging into the files, I find that there were actually six sites that he looked at, and I also said I was sure they were spread out over at least a hundred miles of the Mackenzie Valley; actually, it's several hundred miles. There was one site near Inuvik, one near the confluence of the Root River and the Mackenzie; one near Fort McPherson; one at Firth ; one near the Tanunuck (?) River, and the sixth one at Sans Sault. This is entered to try to clarify that question that Mr. Anthony raised where we got mixed up in the five potential -- five or six potential sites as compared to the five sub-sites at Sans Sault.

MR. MARHSALL: Mr. Scott, we have the letter of October 22nd, which we would like to enter as the next exhibit.

(J.D. MOLLARD AND ASSOCIATES LETTER DATED OCTOBER 22, 1969 AND MAPS MARKED AS EXHIBIT 101)

MR. SCOTT: Mr. Commissioner, I should have entered last week the two slides, I suppose they are called, of the prototype Northern River dry bottom, and perhaps I can enter them as the next exhibit , which I guess is exhibit 100, is it?

(2 SLIDES, PROTOTYPE NORTHERN RIVER, DRY BOTTOM MARKED EXHIBIT 102)

And also I refer to, and should enter as an Exhibit, the article on the Stability of Thawing Slopes, by McRobetts and Morgenstern, which is reported in the Canadian Geotechnical Journal for November of 1974.

(REPORT ENTITLED "THE STABILITY OF THAWING SLOPES" BY McROBERTS AND MORGENSTERN, REPORTED IN CANADIAN GEOTECHNICAL JOURNAL FOR NOVEMBER, 1974 MARKED AS EXHIBIT 103)

JOHN IVOR CLARK
GARRY WOOD HOLLINGSHEAD
EDWARD CHARLES MCROBERTS
WILLIAM ALEXANDER SLUSARCHUK
NORMAN REUBEN MORGENSTERN
RICHARD H. COOPER
R.M. HARDY
GUY LESLIE WILLIAMS, Resumed:

CROSS-EXAMINATION BY MR. SCOTT, CONTINUED:

Q May I ask a question of Dr. Hardy? Dr. Hardy, in outlining your experience some days ago on the Pointed Mountain Pipeline, you indicated that a portion of that pipeline had floated to the surface. I wonder if you could tell us what proportion of the pipeline floated to the surface in that case, in just round figures?

WITNESS HARDY:

A Actually, Mr. Scott, I was referring to the pipe, not at the actual crossing, but on approaches to the crossing in the general muskeg area. It was -- it's completely independent of the troubles they had at the crossing.

Q I understand that. I wasn't trying to connect it with the crossing.

A I;m sorry, I misunderstood you. I just can't give you the percentage of the length of the line, but there were, just from my impression in flying over it, there were several locations where the pipe had floated up above the muskeg in lengths of from 100 feet roughly to 200 feet, approximately.

Q Yes, and how long after the pipeline had been completed did this begin to appear?

A Oh, as far as I am aware it occurred the first year.

Q Yes.

A After the first breakup.

Q Had the pipeline been weighted down at all?

A Not in those locations, no.

Q Was it weighted down in any locations?

A Oh yes,

Q With what?

A Well, they normally used what are called swamp weights there, which are simply concrete blocks, quite substantial concrete blocks.

Q Was any movement of the

concrete blocks noted?

A What's that again?

Q Was any movement of the concrete blocks noted?

A Perhaps Dr. Clark can give you a better answer, a more reliable answer than I can.

Q Speaking of this particular pipeline, does Dr. Clark know?

WITNESS CLARK: I haven't seen this pipeline on the ground but I've seen pictures taken of the part that floated, and one could observe where some of the saddle weights or swamp weights had moved off the pipeline.

Q How would they move off, Dr. Clark?

A Our assessment at that time was that for various reasons they were either not correctly centred, or that there was insufficient lateral resistance in the thawed muskeg, and that under the büoyant force they would tend to move laterally and there would be no resistance there to stop them. That is an assessment made from a picture, though, without on the ground. It was just our speculation as to what had occurred.

Q Well now -- I'm sorry, Dr. Hardy, do you want to say something?

WITNESS HARDY: These concrete weights are made in two sections. There's a concrete

that's split horizontally and there's a bottom section the pipe sits on, and then the top section is simply set on, and it's that top section you see, that is a little bit unstable if it hasn't got any lateral support from the muskeg. I think that's the point that Dr. Clark is making.

Q Well now, how was the buoyancy problem repaired on that line?

A Well, this is not the first line, of course, Mr. Scott, where this has occurred, you see.

Q Oh, I understand that. But I am just asking how it was repaired on this particular line.

A It may be, you see, that you do nothing for some time, but the normal thing and the most economic thing to do is to simply build a berm, berm above the pipe that has floated up. You see, it only stays floated up because the pipe has been bent, and so it's the pipe is not any longer stressed to any extraordinary degree, it's just like -- to get it down is a difficult thing, you see, to apply a loading that will bend the pipe back down, so you will either have to leave the bend in there and roll it over a longer stretch, which is possible, or you can mound up over top of it.

Q Well, how was it done on that particular location?

A I don't know.

Q Do you know, Dr. Clark?

WITNESS CLARK: I don't, sir.

Q I take it it was done, was it?

WITNESS HARDY: It may not have been.

Q Well now, on the alignment sheets, Dr. Clark, there is a reference under numeral following "B" which I understand relates to the buoyancy or the anticipated buoyancy of pipe in the particular route that is referred to on the alignment sheet. Are you familiar with those?

WITNESS CLARK: Yes.

Q Would you tell us what is referred to by B-1 and B-2 in general terms?

A I'd have to and should perhaps take a minute to look exactly at the wording.

WITNESS WILLIAMS: First of all, B-0 refers to no buoyancy requirement; B-1 refers to - indicates that the stretch covered by that B-1 requires buoyancy, anti-buoyancy measures throughout that length, and the B-2 indicates that within that length there are some potential buoyant areas, but not the whole stretch.

Q Yes. Well is then my understanding, Mr. Williams, correct that B-1 means that the area designated requires buoyancy techniques throughout; B-2 indicates that only a proportion of

the stretch indicated requires some buoyancy technique.

A Yes, and that was our best estimate at the time that work was done.

Q Yes. Our analysis of the alignment sheets will show that 44% of the route is marked either B-1 or B-2; would that sound to be a fair estimate or are you in any position to judge?

A Really I'm not, but I think it refers to potential buoyant areas, not known.

Q Yes. We simply calculated B-1 and B-2 and I take it that 44% wouldn't strike you as odd, would it?

A This is in the Northwest and Yukon Territories total, is it, Mr. Scott?

Q It's from Richards Island to the border. The north-south route.

A Yes, I wouldn't argue with you, if you have run through that calculation.

Q Now I take it, Dr. Clark, that a 48-inch pipe is obviously going to be more buoyant than a 20-inch pipe such as was used on the Pointed Mountain Pipeline.

WITNESS CLARK: Yes, it's also a function of wall thickness, but it would be more buoyant, yes.

Q And you have set out somewhere in your application or in your responses, some six or seven techniques that the applicant has available to restrain buoyancy?

A That's correct.

Q Do I understand that in substance, the technique that will be used in most locations, in the vast majority of locations, is burial? Or berming?

A Burial would be the most common one.

Q Yes. I take it from the figures in your application that concrete weights is in relation to burial,extremely expensive?

A Yes, but that concrete weights would be used where open water is crossed.

Q Is that the only place that you presently intend to use it?

A To the best of my knowledge.

WITNESS WILLIAMS:

A I'm afraid I would have to disagree, Mr. Scott. Concrete weights will be used in more areas than flowing water, did you say?

WITNESS CLARK:

A Open water.

MR. SCOTT:

Q Well, what sort of areas do you intend to use it in, Mr. Williams?

WITNESS WILLIAMS:

A I think we've suggested continuous concrete coating in the major river crossings and some of the minor crossings, bott on weights in most of the other minor crossings. Saddle or set on weights in muskeg type terrain, and other areas where they are thought to be the best solution.

I wouldn't restrict it to open water situations.

Q I take it that as between the two methods, weights and burial, which is judged to be the most satisfactory in terms of reducing buoyancy?

A The use of concrete weights is the surest method, the most conservative method. In my opinion.

WITNESS HARDY:

A I think, Mr. Scott, that it should be recognized that from the designer's point of view, he will use the overburden, the back-filling, you see, if he thinks it is adequate. If the conditions are such that it won't be, why then he talks about other situations, except in the case of the open water and the river crossings, where you may go to complete concrete coating, which is a better system, but out of the river valleys, for example in the Pointed Mountain line and the areas you were referring to where the pipe is floated up, you didn't ask me the cause of the floating. It obviously wasn't, the buoyancy wasn't completely

counter-acted. The probable cause of that in that situation was the fact that the backfilling, it was figured to be held down by backfilling, and the back-filling wasn't adequate. It was mostly muskeg, which has very low unit weight.

WITNESS WILLIAMS:

A Mr. Scott, can we just back up to the previous question with respect to the percentage of total weighting requirement. Is it correct that 40 or 45 percent you arrived at, includes all of the distance, the lengths covered by the B-2 situation?

Q All the B-1 and B-2 situations on the alignment sheets.

A Recognizing that --

Q From Richards Island to the Alberta border.

A Yes, sir. Recognizing that a B-2 situation is not intended to be weighted or anchored for the full length of that section?

Q Yes, I think I understand that the B-2 designation does not indicate that there will necessarily be a buoyancy problem of substantial proportions at every place in the B-2 segment?

A Right, thank you.

Q Now Dr. McRoberts, you -- I want to ask a couple of questions of you as a result of your -- a report you have prepared on pipe interaction at single field bends and your report, as

I understand it, studies interaction at overbends, that is a bending up and down of the pipe at sidebends and at sag bends, which have already been described as the point at which the pipe bends to cross the river.

Now, do I understand correctly that thermal expansion, that is heat expansion, and the pressure of gas in the pipe, both cause a compressive force in the pipe?

WITNESS MCROBERTS:

A Yes, that's correct.

Q Yes. And what is the result of that compressive force in just one or two words?

A If the pipe is not restrained, then depending on the conditions and the amount of compressive load or force in the pipe, then unsafe conditions could ensue.

Q Well, what sort of unsafe conditions?

A You would get to the point where the serviceability limit in the pipe is exceeded.

Q Well, does the pipe move as a result, or may it move as a result?

A In the type of calculations we do, we assume some movement of the pipe.

Q Yes. Well, how do you -- I take it that one of the consequences of this combination of forces, can be that the pipe will rise

out of the ground, or may rise out of the ground?

A If the pipe wasn't properly designed, yes.

Q And how is that restrained, how is that movement restrained?

A In which type of situation are you thinking about?

Q Well, let's deal with overbends.

A There's two methods of restraint, one takes into account the overburden resistance on the top of the ditch -- excuse me, in the resistance of the soil above the pipe along the ditch; one also takes into account the resistance that is mobilized between the pipe and the surrounding ditch backfill, the tangential resistance.

Q I take it that you found in your report, the latter factor to be relatively minor in terms of control?

A We took a conservative value and the range we were at, it had a minor effect, although because we picked a very conservative value it did have a minor effect.

Q I take it then that assuming a conservative value for that factor, the response in terms of this pipeline is again likely to be calculating the appropriate amount of overburden in each case?

A That's correct.

Q Yes.

A Or limiting the bend angle.

Q Or limiting the bend angle. Now Dr. Hardy, do I also understand that at Westcoast and Trans-Canada this problem of the over-bend moving up and out of the surface of the earth has occurred?

WITNESS HARDY: When you said "Trans-Canada" did you mean "Trans-Mountain?"

Q I think I meant Trans-Canada.

A I've had no experience with Trans-Canada.

Q Well, let's deal with Westcoast Transmission then. Isn't there a very graphic picture of a case where this has occurred?

A An upheaval due to stress?

Q A case in which a combination of thermal expansion and gas pressure has led the pipe to move up out of the ground.

A I think they have had at least one case of that. It hasn't come within my specific terms of reference with them. They recognize it as being a stress problem. It's rare compared to the floatation case which I have had input into, in the case of the floatation; but I'm

sure there's at least one case where this has happened all right.

Q Well, Dr. McRoberts, would you agree that in dealing with this pipeline, assuming no remedial measures for the moment, that because the pipeline is a larger diameter, that is 48 inches, because the gas will be under higher pressure and bearing in mind the temperature increases between the deep winter and the middle of the summer, that leaving remedial measures aside, that the possibility of this kind of movement of the pipe is greater in this instance than in most other pipelines?

WITNESS McROBERTS: The problem is more significant in over-bends. Side bends are by and large the same, although a little worse; but I would say yes, as the pipe gets bigger and the pressure gets larger, it is an inescapable conclusion.

Q And I take it the variation in temperatures is also a factor that increases the dimension of the problem if there were no remedial measures, from let us say minus 50 degrees when it's constructed in the winter to 50 degrees Fahrenheit in the middle of the following summer.

A Yes, but when you talk about 50 in the pipe, you must keep in mind that we are operating or propose to operate a chilled pipeline, and the 50 in the summertime would be a

ground temperature in an unchilled, non-chilled line and then you wouldn't have the gas pressure, so by and large given the two numbers that you've quoted, we wouldn't be encountering them.

Q Are you telling us that the range of temperatures is not a factor in this phenomena on this pipeline?

A Oh yes, but I wasn't agreeing with the two numbers that you gave me, north of 60.

Q What you're saying is that the range of temperatures, bearing in mind that the pipe is below ground level, at the start is not likely to be as great as the range that I suggested to you.

A What I was suggesting to you was that you take a figure of minus 50 below, I don't think we'd be stringing the pipe together when it was that cold. I think we would stop when it was substantially warmer. That's one end of the scale, the top temperature you mentioned was plus 50, north of 60 we are proposing to operate chilled gas pipeline and the temperatures there won't rise much above 25, so the temperature differential then would not be as much as you are considering. However, we could get plus 50 in the pipe, I suppose, prior to start-up, as the ground warmed up; but at the same time we wouldn't have any gas pressure to 1,600 p.s.i. So therefore it wouldn't be fair to say high gas

pressure and exact temperature range you mentioned. I would point out that the temperature differentials per se can be a lot higher in pipelines constructed in the wintertime when in the temperate regions of Canada because they don't chill and are operated at a much warmer temperature.

Q Isn't it possible that the compressive forces generated in that way could be of a higher order of magnitude than the overburden or the fill?

A They could it you weren't designing, Mr. Scott, but we propose --

Q If you weren't?

A If you were not doing a rational design; we propose to do a rational design as a matter of good engineering practice and wouldn't let that condition develop.

Q Well now, Dr. Clark, we've discussed over these days in a general way, three situations in which it is at least conceivable that if there is not adequate design that the pipe can come out of the ground. One is -- or come above the surface of the ground -- one is frost heave, one is compressive forces of the type we've just discussed, and the third is buoyancy, and what I'd like to know is in those circumstance what remedial action is going to be the action of choice?

WITNESS CLARK: Well, in all instances the design philosophy is to prevent

it coming above the ground under any circumstances.

Q Well then, you won't need any remedial action. I understand that, but in the event that one of these predictions plays you fase, what is the -- how are you going to remedy it?

A Well, in the case of frost heaving, it would occur over a much longer time frame than the other two that you mentioned, and I can't conceive of it happening due to frost heave since we would be monitoring and we could take a remedial measure before it got to within the height of the original ground surface, that we had allowed for it, and that would involve further surcharging during a winter period sometime during the first few years. In the case of the --

Q If I could just stop you there for a moment, do I understand then that the only remedy in terms of frost heave and the remedy which you judge to be adequate will be increasing the overburden?

A Well, that's not the only one.

Q What other ones do you --

A Well, two others immediately come to mind that I think we've mentioned them both, and that is a localized melting of ice lenses to allow it to go back down.

Q Yes?

A And a third would be a localized freezing, and that is accelerating the penetration of the frost bulb so that the overburden pressure, shut-off pressure is approached much more rapidly,

Q I take it that of those three, however, overburden is the remedy of choice.

A In a large area that would be the remedy of choice, but on a localized area I would think one of the other two would be more economical.

Q Yes. What sort of an area is a localized area, in terms of selecting one of these remedies?

A I couldn't put a number on it but I would think something over a few hundred yards.

Q Would require overburden solution?

A Would require -- could be any one of those three.

Q Something under a couple of hundred yards?

A Something within a few hundred yards.

Q Within a few hundred yards.

A It could be any one of those three.

Q Well now, I'm sorry, you were just about to go on to one of the others.

A Well, the other one is the pipe coming out of the ground due to the forces associated with the difference between the lay-in temperature and operating temperature, and the internal pressure. This of course is a transient problem since it diminishes as the soil freezes and the backfill freezes. Again, the problems associated with effecting a remedial measure there would be so great that our design approach would have to be conservative, in other words we are not counting on a remedial measure to accommodate that particular situation in any instance. An unforeseen circumstance, the remedial measures would probably involve -- could be a short shut-down until the repairs were effected,and again it would involve increasing the surcharge load, would be one approach.

Q Well, do any other approaches occur to you?

WITNESS McROBERTS: Mr. Scott, there is one thing I should also mention with regard to over-bends and sag bends or side bends, one procedure that pipeliners follow as a matter of course is what's called hydrostatic testing, and they use pressures that are in excess of the gas pressure that one uses in the operating line, and in fact the temperature differential to be used in that -- at that time would be higher than the operating pressure differential. In fact, while we were still in the field we would be

loading the pipe with a greater pressure --

Q You would or you wouldn't be?

A We would be loading it in the field while the construction spread is on the ground, as it were, over sections, and we would in fact be proofing the whole design as well.

Q Well, Dr. Clark -- thank you -- Dr. Clark, you were going to go on, I think, and mention some other methods.

WITNESS CLARK: The first method would be if during the testing and so on that this hadn't been revealed, and I can't conceive of a situation where it wouldn't be, but the --

Q Are you speaking of pressure or --

A I'm speaking of the compressive stresses in the pipe, causing a reaction that would cause it to come up at an overbend, and the one that would come to mind, the first choice, would be increasing the sur harge load. The second would be possibly shutting the system down and dealing with the pipe, replacing it.

Q How would you deal with it and replace it?

A A section could be removed and replaced, ot cut and replaced. I'm not that familiar with the operation and maintenance techniques in that situation.

Q I take it that the overburden solution is one that has to be applied literally in the course of construction rather than later. It's not a solution in short it would be available if the raising of the pipe is a fait accompli.

A If it came right out of the ground, that wouldn't be available, no.

Q So, would I be correct to say then that it is a remedy that has to be applied at the same time as the pipe is being laid?

A It would normally be part of the design but if during the testing one got an indication of a potential weak area, it could be applied at that time.

Q Yes, and the second method

I take it is to replace new pipe, is that the solution?

A Or to cut out the particular piece affected and put it back down in and replace it.

Q Now, what about the third, buoyancy?

A Well again the problems associated with remedial measures for buoyancy are pretty severe, which has given us cause to take a very conservative approach.

Again, I can't conceive of a situation where we could have buoyancy. Buoyancy is also, in many areas, a transient problem in that once the complete backfill is frozen in, it would no longer be subjected to flooding, except where there is open water.

Q Yes, but I take it that with respect to buoyancy, increasing the overburden isn't going to provide a solution , except to create a great mountain of sand or earth?

A After it has happened, you mean?

Q Yes?

A That's correct, it would very unlikely be a solution.

Q wouldn't it be true that the only solution in the event that that problem develops, is to retrench and bury the pipe again?

A The trench would certainly have to be cleaned out and possibly widened, and the pipe would have to be weighted or else held in the

ground with some type of anchoring.

Q Yes. Is the presence, with respect to a buoyant pipe or a pressure problem pipe, of an ice bulb going to create any difference, the frost bulb?

A The frost bulb?

Q Yes.

A Once the frost bulb is starting, there's no longer access to the water -- for the water in sufficient quantity to float the pipe. This is what I meant, that it was a transient problem. Largely associated with the inactive season between construction and time of start-up.

Q Dr. Clark, I wonder -- I want to ask you some information about bore holes, and I wonder if you can get before you the first alignment sheet of the cross-delta alignment sheets. It's number 1K0200-1005. I'm sorry, it's not the first one, it's A-0200-1005. Well now I really want to perform a little exercise to see that I understand how you read the bore hole information as it may become significant, when we don't have this panel with us.

Now, I take it that at the top of that page are bore hole logs, the quadrilateral boxes that are shown one following the other along the top of the page?

A That's correct, yes.

Q And the number at the top of the log box refers to the alignment sheet where the same number can be found, and that is the placement

of the bore hole, is it?

A That's correct, yes.

Q And the date I take it below that, is the date on which the bore was taken or the sample was taken? For Example, N 74-800 april, 1974 would be the date of that bore?

A That's my understanding, yes.

Q Yes. Now I also understand that if you know how to read those logs, they show the depth of the various levels of soil as revealed by the bore?

A Yes, sir.

Q For example, on that log you see the depth 200, 350 and so on? Pardon me, it's 20.

A Yes, 20, 35.

Q And that bore, for example, is 97 and a half feet, would that be correct?

A Yes.

Q How does it show the kinds of soil at those various depths?

A It's shown by the symbol which relates to the unified classification system.

Q And I take it the unified classification system is a traditional system of identifying various soils?

A That's correct.

Q And I think in the material you have filed, there is a catalogue of what those

shorthand abbreviations refer to under that system?

A That's correct. There's a legend in the right hand corner. There's some modifications to the unified system,but nothing very extensive.

Q Now, I take it that the bore hole diagram also shows the amount and form of ice and/or water that's to be found in the soil?

A Some do.

Q Yes. Could you take one of those and perhaps N-74800 and show us how you determine that from the bore hole log?

A Well the shaded portion would indicate that it's frozen for the entire depth. The symbol --

THE COMMISSIONER: Just so I'll know where we're at. The bore hole N74-800 was a bore hole that you put down in April, 1974 at the west side of Shallow Bay, where the pipeline -- where the two pipelines, the dual lines, enter Shallow Bay.

We're talking about the same thing here?

A That's correct.

MR. SCOTT: Q How do we determine the form of water, or the presence of water?

WITNESS CLARK:

A I believe that the right hand column of each of those particular boxes shows the moisture content.

Q expressed in percentages,

I take it?

A Percentage of water related to the percentage -- or the weight of water to the dry weight of that particular sample.

Q Yes, but out of hundreds?

A Percentages, yes.

Q Yes. Now, is there information concerning these bore holes, that is not shown in the diagramatic box on the top of each alignment sheet? For instance, what about the compactness of the sediments? Is there anything that shows that?

A The dry density and perhaps outer break limits and grain size distribution would not be shown on this particular log. That would be shown on a full test hole log that would accompany the report, the geotechnical report on this.

Q But I take it that that information is available in that book which has been filed?

A If those tests were run, and I don't recall to what extent, except I know there were some grain size curves run, and if the normal routine to run, if you have an undisturbed sample, to run a density test as well as outer break limits if it has a plasticity index.

Q Wold it be correct to say that in the bore hole book that you have filed, if you've got it it's in that book?

A Yes sir, it should be.

Q If it's not in that book at the date of the filing of the book at least you didn't have it?

A That's right.

Q Now apart from that, what other kinds of information about bore holes would you normally have?

A Well normally you have a visual classification of the soil type in the ice. You might run thaw consolidation tests. You might run strength tests. These are fairly routine tests that we run on occasion when required.

Q Now just looking at this sheet, for example, is there any way that you can tell from the sheet whether the sample shown with respect to any bore hole log is undisturbed or a disturbed chip sample?

A No, you couldn't tell from this sheet. You would have to go to the original log where there are symbols that indicate whether it's an undisturbed or pored sample.

Q Could you just explain briefly the difference between a chip sample and an undisturbed sample?

A A chip saple would be

cuttings that are brought up often by air from the cutting teeth at the bottom of the drill rod, and at various intervals we then put a core barrel, usually in frozen soil we use what's called a core barrel where we core for some number of feet, two to five feet, and that is then brought up and it's packaged and kept in an undisturbed frozen manner until it reaches the laboratory.

Q Would it be correct in layman's terms to compare the two this way, an undisturbed core sample is one in which a dimension of the earth is simply lifted out and remains intact and physically undisturbed until it is analyzed?

A That's correct.

Q A chip sample, on the other hand, would be a sample, would be the kind of sample that would be produced for example if you used an ordinary drill and got, as you would in the case of wood, shavings coming out the top as the drill went down,

A That's correct.

Q Do you know what proportion of the drills on which you've relied are based on chip as opposed to core samples?

A I haven't made that analysis. The information should be available on the logs.

THE COMMISSIONER: But you say, looking at this alignment sheet, we don't know whether these samples are the one or the other type?

A In fact the alignment sheet doesn't show where samples were taken.

MR. SCOTT: Except in a general way.

A In a general way relative perhaps to the moisture contents, but there could be more, and the detail logs show all of this information.

THE COMMISSIONER: Well, do you say that this alignment sheet that I'm looking at doesn't show where the samples were taken? Do you mean the geographic location throughout?

A No, I'm talking about depth of any particular bore hole, the intent of these is not to show that at 4 1/2 feet we took an undisturbed and at 8 feet we took a chip sample and so on. That's in the more detailed log that would accompany the geotechnical data report.

Q But this purports to show -- all right, what does this purport to show, this N 74-800?

A It shows --

Q How much farther ahead are we now that we've gotten it?

A It shows the soil profile.

Q Yes.

A Whether it's frozen or unfrozen and evidence of visual ice, according to a classification system and it shows moisture contents.

MR. SCOTT: And the particular

depths are shown, aren't they, by reference?

A Yes, to the various stratification.

THE COMMISSIONER: Well, the soil stratification from 80 feet to 97 1/2 feet you classified it, what does that mean?

A That means that it is a silt of low plasticity with a trace of fine sand and a trace of organic material in it. It's frozen with some visible ice;moisture content ranges from 31 to 33% within that depth range.

Q I take it because there is no ice shown at the top of the bore hole, the same way as appears at N 74-801, that - - N 74-800 was not actually out on the ice in Shallow Bay?

A That's correct, that would be back on the dry ground at that time.

MR. SCOTT: Well now, Dr. Clark, I take it that in the bore hole logs, the ground ice designations that are used are those that are laid out in the N.R.C. Technical Memoranda No. 79.

A That's my understanding, yes.

Q And I also am led to believe -- and I'm easily led on this sort of subject -- but I'm led to believe that these designations are intended for use only with respect to undisturbed samples. That is not with respect to chip samples.

A My understanding is that

the classification system allows a drilling supervisor, if you like, to give a broad classification of the occurrence of ice and are used of course most reliably with undisturbed samples, but certainly from observing chips, one could get a good feeling within the bounds of the classification system as to the type of ice and quantities of ice there.

Q Well, apart from a good feeling, I take it that you would perhaps then agree that there is a potential inaccuracy when these descriptions are used with respect to chip samples.

A And even with core samples.

Q But more so with chip samples. Is there any doubt about that?

A That's probably correct, but the classification even of soils where one classifies a sandy silt or a silty sand in the field, is problematic, within small limits.

Q Well now I take it that because permafrost is really a temperature phenemena, the physical description of the bore hole sample as either frozen or unfrozen, without any temperature data really doesn't tell the whole story, does it?

A No, it doesn't. We normally have -- would like to have occasionallythermister strings in bore holes.

Q Yes, and I take it that this is so particularly when the ground temperature is relatively close to the freezing point, a margin there

can make an important difference.

A That's correct, yes.

Q Well, how do you get your temperature data, or do you have it?

A We have temperature data from a number of thermister strings that are put in the ground. Several of them date back quite a few years. We periodically read them. We read them a few hours after installation as well, or at least at a time after installation such that it would represent the equilibrium condition .

Q Well, are those part of the bore?

A I'm sorry, part of --

Q Are those inserted at the time the bore is taken, or are you talking about something entirely different?

A Normally at the time the bore hole is made.

Q Yes.

THE COMMISSIONER: They tell you what the temperature is, do they?

A That's right, sir.

MR. SCOTT: And that can be of significance, I think we've agreed.

A Yes sir.

Q Well, where would you find it, for example? I don't see any on this particular sheet, for example, any way of telling the

temperature.

A No, it doesn't purport to tell the temperature. We have -- if in this particular series of bore holes a thermister string was installed, it would normally be included with the geotechnical data report.

Q I am advised that on some of the bore hole logs, which are shown on some of the alignment sheets there is a temperature figure. I don't want you to get the page out unless you would consider it helpful, but on bore hole 3033 as it's numbered, there is after it in brackets the figure (88).

A I better have a look at that. 3033, (88).

Q It's on the alignment sheet, the main alignment sheets 1 A-0200-1003.

A What was the first two numbers?

Q 1 A-0200-1003. If you look at the third in, bore hole 3033, do you have that?

A Yes, I have.

Q Now I understand that the figure that appears in brackets in that case, 88, is the number assigned to the probe, the temperature probe, would that be correct?

A That could very well be but I'm not certain of that.

Q Well, what I am concerned to know is how do we tell if you have a temperature reading for any given bore hole, and if you have one, where do we find it? I found one part of the answer for myself.

I think if you look at the index page to that book, or the upper left hand corner, it shows the number, the drill hole number, and then following it in brackets, the temperature probe installation number.

A That's correct, yes.

Q So, am I correct then that in those cases where you have a temperature probe installed, that it will be shown that you have one on the bore hole?

A It should be, yes.

Q Yes. Now, where will we find the temperatures?

A They should be in the geotechnical data report.

Q My information, Dr. Clark, based on account, is that there are only some 22 temperature probes on the entire route. Do you have any information as to whether that is reasonably correct?

A No, that's not correct.

THE COMMISSIONER: There would be more, would there?

A Yes, sir.

I believe in direct evidence I

stated that my estimate was around 100, and I think it's between 100 and 120.

MR. SCOTT:

Q Well, we've added them up in this method on the alignment sheets, and we find that there are four at Swimming Point; there is seven near Norman Wells or in that area; and that there are only about 10 others elsewhere along the entire length of the route.

What I would ask you to do, and I don't suppose it has to be done today, is to figure out whether there are temperature probes other than those disclosed on the bore hole diagrams, and if there are, put us in touch with some kind of way of figuring out where they are and what they read.

A I would be happy to do that, and not all of the bore holes, of course, fall within the alignment sheet window with the temperature probes, but we do have a summary of all of these, when they read, at different periods of the season, how long they have been in operation and what the temperatures were, so I would be happy to provide that.

Q Well perhaps what you can do first, is to determine whether my way of finding out the information with respect to the windows on the alignment sheets is correct, and then determine whether there is temperature information beyond the window?

A Yes, we can double check

that.

Q In short, what we want is temperatures on the routds, not temperatures that may be found in bore holes elsewhere.

A By elsewhere, I'm sure you would be happy with one in any given physiographic region.

Q If it's the only one you've got, I guess we are going to have to learn to live with it.

A Some of the initial geomet- stations were selected, as I understand it, to represent a particular climatological region within a physiographic division.

THE COMMISSIONER: Well, if there is this discrepancy, Dr. Clark, 20 temperature readings apparent from an examination of the alignment sheets, and yet you did 120 or thereabouts, are you saying that there must be 100 temperature readings that were taken along the route, but not within the window that we're looking through when we look at these alignment sheets?

A That's one possibility; the other possbility is that some of the temperature probe numbers might have been inadvertently left off. I would think that the first is more common, and that they would be outside this present alignment sheet window.

Q This one we're looking at is the crossing of Shallow Bay. That's the longest river crossing, the widest river crossing in this

whole route, isn't it?
A Yes, sir.
Q And how wide is Shallow Bay at this point?
A I believe it's about four and a half miles.
Q And it is shallow, we are led to believe, but these holes that you drilled in Shallow Bay, and there are only three of them actually beyond the shore on each side, appear to be very shallow holes. Fourteen feet, eight feet and eight feet.
Now, if I'm not reading this correctly, let me know, but would those holes take you to the depth at which the pipe is to buried across Shallow Bay?
A The objective of those holes, sir, was to find out how deep the bottom was frozen. But they wouldn't take us to the depth that we would propose to bury.
Q Well, nowhere then between one side of Shallow Bay and the other is there any bore hole that actually took you to the depth at which the pipe is to be buried?
A No sir, that was due to the type of rig that was being used, which as I understand it, could not sample unfrozen soil. Once we go through the frozen material, there was little to be learned about going to deeper with that particular rig. This was a preliminary type of investigation where our

intent was to observe where the banks were frozen for the full depth and during this period, how far frost penetrated below the ice cover into the bottom in those shallow regions.

Q Well then, this crossing which is the longest crossing that you face along the whole route, you have no bore holes that tell you what the composition of the soil is beneath the river crossing, beneath the crossing of the bay?

A These holes don't tell us that, other than by extrapolation from the on-shore condition to the off-shore condition . There may be holes by others in that area that we have available to us, but I'm not certain of that.

MR. SCOTT:

Q Dr. Clark, the difficulty that confronts me is this: One of the concerns that is raised, has been that there may be permafrost below Shallow Bay, and because -- no, let me begin again.

The concern that has been raised is that if there is no permafrost below Shallow Bay, there may be a frost heave problem with respect to the pipe under Shallow Bay. Now, whether that concern is accurate or not, or worthwhile or not, I take it that at the moment, you have no way of determining whether there is permafrost below Shallow Bay, according to these drill holes?

A These drill holes wouldn't tell us that, but historically in that area with that large open body of water, where it doesn't freeze over

the whole area, we would not expect to find permafrost.

My understanding is that we have discussed this with, for instance, with Dr. MacKay and have gathered information from him as well as our bore holes.

Q Well, he doesn't have any drill holes, does he?

A I'm not sure that he does not. I think he has available to him, a lot of drill hole records in the delta.

Q Well, the response that some members of the panel have made with respect to the problem of frost heave below Shallow Bay, as I understand it, is that even if there isn't permafrost there, and even if frost heave is potential, that the sediments are compacted, and therefore the chance of frost heave is reduced, I'm sorry, uncompacted, and the frost bulb is going to compact them down and therefore not heave up. Isn't that the sort of theory that is given to us.

A That's part of it, and the other part is they tend to be fairly sandy, or silts of very low plasticity which have low shut-off pressures.

Q Well, assuming you were to find out that Shallow Bay is in fact without permafrost, have you any way of telling whether the sediments are compacted or not?

A We have assumed that it's without permafrost, because it's the most conservative

the whole area, we would not expect to find permafrost.

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A We have assumed that it's without permafrost, because it's the most conservative

assumption, and yes, we will be doing drilling programs there, but we will be using specially designed piston samplers for instance, to get undisturbed samples which will tell us density.

Q Yes --

THE COMMISSIONER: Specially designed what?

A Piston samplers. You see, in compacted soils of deltaic deposits are very hard to sample but there has been equipment designed, my understanding is that it's been used off-shore in the delta deposits very successfully with a hundred percent recovery that would be suitable for sampling these types of soils. But it's not a routine matter to get a good, undisturbed sample of a very loose deposit.

We feel now though, and have consulted with people specializing in that type of equipment, that the eqipment is available to do that now.

MR. SCOTT:
Q Well, would it be correct to summarize the question of frost heave under Shallow Bay this way, that there is no bore hole information that tells us at this point in time whether there is permafrost under there or not?

A There's none indicated in our alignment sheets, Mr. Scott.

Q All right. And in the second place, if there were no permafrost and the potential for frost heave was therefore there, there

is no information that tells us whether the condition for your response, namely uncompacted soils, are there or not?

A No, we are not relying on the soils being of low relative density. We're relying more on the shut-off pressure and if necessary, we can go to a deeper burial. We think that the fact that they have low relative density will assist us in the frost effects assesment or potential, that it would have less potential. There is evidence of this, substantial evidence, that very, very loose silt deposits develop ice lenses, but not much of a heaving pressure.

Q Isn't this, Dr. Clark, another specific instance of an area in which much more intensive drilling is going to have to be done before final design?

A Yes, we will be doing much more drilling here before final design.

Q And I take it that in connection with that you will have to do much more testing of temperature or determination of temperature from spot the spot on the routes.

A We would do some more, yes.

Q Now, with respect to those additional bore holes that you will put in, you and the other witnesses have told us of specific kinds of problems areas where you would contemplate bore holes. Do I also understand that you are going to do additional bore hole work on the overland areas of the route too, and I'm leaving out the rivers and the slopes and the particular problem areas.

A In some areas, yes.

THE COMMISSIONER: Well, Dr. Clark, the only bore holes beneath Shallow Bay itself were the bore holes that you put down to determine how deep the bay was.

A No, how deep the frost penetrated. We determined the depth of the bay by soundings.

Q To determine how deep

the frost was?

A How deep the ground was frozen into the bottom, yes, at those holes.

Q All right. Now those holes were done in April, 1974, a year ago.

A Yes sir.

Q And there have been no holes drilled since to which you can refer the Inquiry.

A Some of these holes were drilled in September of '74.

Q I'm looking at the holes --

A Oh, the ones in the middle? No, they would be --

Q No, the holes from one side of Shallow Bay to the other, leaving aside those clusters right at the shoreline.

A Yes, those were drilled in April of '74, and on the other side there were some drilled in September, but no holes were drilled in the open water in September.

MR. SCOTT: well, Dr. Clark, let's leave aside the problem areas such as river crossings and marginally unstable or potentially stable slopes or whatever they are, and areas of that type that have been discussed with particularlity, and let's just deal with the overall route. Now, you have told us that some bore hole drilling will be done on the overland portions of the route.

A That's correct.

Q Now what I'd really like to get from you is some kind of indication of how often it will be done, what the spacing will be between the bore holes as you move to final design.

A There's no possibility we could give you that indication. For one thing we will be doing geophysical surveys in certain areas that will only, after that is done we will determine that. In many lengths of the route, I am sure, we will not require any additional bore holes.

Q Well, the recommendation of the Department of Public Works, as you may know, for the Mackenzie Highway, is that on the route bore holes should be taken every 1,000 feet or approximately 5 to a mile. Now, are you going to have the spacing program of any type at all like that, or what?

A Not as a generalized rule like that, because their requirements are so much different from ours.

Q Well, what concerns me for example, is that if you look on the alignment sheets for the cross-delta route, you find for example, that the bore holes you have are quite often three or four miles apart, and there is one space of some 30 or 32 miles where there aren't any bore holes at all. Now, what is going to be done about that?

A Where is the 32 miles where there are no bore holes?

Q The easy way to find it

is to refer to Mr. Williams' summary, I think. I can perhaps find the sheets for you. By Travaillant Lake, we start on sheet No. 1 L-0200-1017.

MR. MARSHAL: Is that Exhibit 87 to which you're referring?

"Drill hole data for pipeline routing in Yukon Territories and Northwest Territories."

MR. SCOTT: It's the alternative cross-delta routing alignment sheets.

MR. MARSHAL: The information as to the drill hole data, is that Mr. Williams' summary of that?

MR. SCOTT: That isn't where we got the 30 miles, but I think it's reflected in that.

THE COMMISSIONER: I think that was an exhibit. Do you have it, Miss Hutchison?

MR. SCOTT: We have analyzed on the basis of this information that just near Travaillant Lake there is about 30 miles where there are no bore holes at all, and I wouldn't be perturbed about that because you've told us that much more is going to be done. I'm anxious, if I can, to get a statement from you about how it's going to be spaced?

A The spacing is normally a function of the variability of the terrain. The homogeneity, and what other information is available in that general area.

Q Well, do I understand that it is not possible for you on that basis to give any other answer?

A Not right at this time because I don't think we can generalize on spacing.

Q So that I suppose it's conceivable that you might go ahead to final design and have an area of 30 miles where there are no bore holes.

A That's inconceivable to me.

Q Well, why is that inconceivable?

A Well, it's just normally that I can only think of one area where there is a long stretch now with no bore holes, and I'm not sure that it's Travaillant Lake. Again there was a lateral shift there, so as I say, there are no bore holes, you can say there's none in this alignment sheet window. The terrain units would no doubt have bore holes.

Q No, but I put it to you that it's inconceivable because you would agree surely, that one of the principal sources of your information as to the quality of the soil and its iciness or not in the ditch and in some areas more important below the ditch is to be found from the bore holes.

A Not exclusively.

Q Not exclusively, but it's one of your principal sources of information.

A It's a ground truthing as we have used them now, but it's not the only tool we use.

Q Why do you regard the standard as selected by the Department of Public Works for the Mackenzie Highway as inappropriate to a gas pipeline?

A Well, the criteria for a highway is just so much different than for digging a ditch.

Q For digging a ditch and putting a pipeline in it, is that what you're saying?

A Yes, the criteria for the highway is just much different.

Q Well, when you say "the criteria", what do you mean, the government criteria?

A No, the requirements for a highway design.

THE COMMISSIONER: You mean the criteria of good engineering practice, is that it?

A Yes, they are concerned with the fill that they are building up has to have certain structural qualities, and they require support from the sub-grade whether in a thawed or frozen condition.

MR. SCOTT: Well, mightn't it be so, Dr. Clark, that there is little criteria for good engineering design in chilled buried pipelines in this country? That's obvious, isn't it, at this stage?

A No, I think the criteria we have established is good.

Q No, I shouldn't have used "criteria" perhaps in that sense, but the experience.

A The experience is limited to the test sites.

Q Yes, and that therefore at least in this sense you are proceeding on a voyage in which there are a good number of unknowns.

A It's a matter of level of detail. I don't see any major unknowns. For instance the drilling of test holes, unless it can reveal some significant information that we don't have, even though I like drilling lots of test holes, I would be irresponsible if I recommended something that wasn't appropriate.

Q Yes. Do you make the same observation with respect to the areas of discontinuous permafrost?

A No, it becomes a little more important in discontinuous permafrost than continuous.

Q Well, is it -- am I correct to understand that what is really happening here is that you are placing your reliance not on mile by mile bore hole analysis, but rather on the geothermal computer analysis?

A Not entirely, no. We have the terrain typing as well.

Q Well, leave aside the terrain typing for the moment, isn't it reasonably

clear that you're putting your eggs in the geothermal analysis basket?

A Only for the ground temperature regime.

Q Well now, in the evidence given by panel 1, we were told -- I don't have the reference for the moment so you'll have to take my word for it -- but as you move toward final design there would be a progressive upgrading of the terrain typing on the alignment sheets. Is that your understanding of what will happen?

A My understanding of what will happen is that the analysis of terrain typing that we have done now, which includes all of the bore hole information that has been made àvailable to us, would be updated as any more bore hole information becomes available.

Q It's not going to be updated any other way, is it?

A I don't follow that question.

Q But panel one tells us that it's going to be updated.

A Yes.

Q You have told us,and your panel has told us, that there will be more bore holes at specific locations where there are problems, and that there will be some more bore holes where there are changes in terrain, but you're unable to say, at this moment, how many.

I take it there is no other way in which this terrain typing can be affectively upgraded?

A It could be upgraded by a couple of other ways, one is by on the ground reconnaissance, both by ourselves and others in areas where there is some question now as to the terrain typing. We have given a number of those examples in one of the reports listed, I don't have the number, where we compared the terrain typing with the G.S.C., surficial geology work for instance.

We would also have our geophysical studies that would be informative.

Q So that the updating is going to depend on reconnaissance, the geophysical studies and bore holes?

A Yes, sir.

Q And I take it that you're not in a position at the moment to tell us how much of any of this will be done?

A Not at the moment, that is one of the studies we are undertaking now.

Q I note, for example, that on the cross-delta route, the terrain typing map show the whole delta to be one terrain type, I think it's MRD, or something like that. Isn't that a classic case where more sophisticated terrain typing may be required as you go towards final design?

A MRD. is the Mackenzie River Delta.

Q Yes, that's the terrain type, and you know, the whole delta is shown as one terrain type. I'm sure I couldn't have told you that in advance, but you know, it doesn't seem to me that it's very sophisticated mapping at that level.

A I believe the bore holes show a relatively homogeneous material through there. There may be subtleties in soil types that would be of interest to us, but it's pretty homogeneous.

Q So do I understand then that you don't contemplate any upgrading in that area?

A We certainly contemplate additional bore holes.

Q How many?

A As many as required to effect the final safe design.

Q I guess I will get through this one way or the other.

When are you going to have that information?

A On the Mackenzie -- the delta bore holes?

Q The whole shebang, what your bore hole program is going to be?

A I'm trying to recall our schedule. As I'm sure you realize by now, we do this I think, in a very logical way.

Q You are not asking me to answer that, are you?

A I believe the plan,the project plan calls for us to have our final field drilling programs pretty well outlined within this year, and some of them will be initiated this year.

Q Well now, one or two other matters. Are the alignment sheets for final design to be prepared on a larger or a bigger scale than the present ones?

A They will be orthophoto-mosaics at a scale of one inch to a thousand feet, with approximately a two and a half mile strip centred on the line contoured.

Q What's the contour interval?

A It varies, along the line, I'm going back to recollection here, I believe it's five feet, but at specific sites it would be down to two and a half feet.

Q Well now the present sheets have a profile I think at the top, which has I gather, been prepared from information available on existing maps; you're familiar with that?

A Yes, that's correct.

Q When would the Survey in your sequence ordinarily be prepared and shown on the profile?

A The actual field survey?

Q Yeah, or when is the -- is there going to be a survey done that will provide on the maps a survey profile, apart from topograhic maps?

A Yes, that's my understanding.

Q Yes.

WITNESS WILLIAMS:

A When the orthophoto mosaics are obtained, of course that will provide a much more accurate profile than what we have shown now. During the time of the location survey and on the ground profile will also be taken.

Q Yes, I take it that for the purposes of final design, the orthophoto maps are going to provide the profile? You won't have done any surveying at that stage?

A I would think for a good percentage of the route, if there is some areas that required some more detailed field work, certainly it would be done.

Q And I take it just so I'll understand it,orthophoto maps are just more precisely detailed and sophisticated maps or photographs than a topographic map or an aerial survey map, might be?

A Yes, the photographic window will be similar, but as Dr. Clark has just described, to a different scale than what we have shown in the application, and they will be photographically assembled on the sheet in a manner that will give you a much truer picture of physical features and so forth. It takes out the distortion of the photography, so that the mosaics can be -- you can use a scale on them, for instance, to much better accuracy than the ones that we have submitted.

Q Well now, in your evidence you have, Dr. Clark, reported that after the pipeline ditch has been excavated, you will prepare a geological profile of the route, I presume made from the ditch itself?

WITNESS CLARK:

A We would collect pertinent data from the ditch and incorporate it into a data retrieval system.

Q Yes. Now, in the canned evidence, I don't have the page, you refer -- and I just want to be clear, to the preparation of that catalogue, as you call it, prior to and during construction.

A Yes.

Q Now, does prior to mean

sometime prior to, or does it mean simply immediately after the ditch is dug and immediately before the pipe is buried?

A No, the system will have all of the information that we have now, incorporated into it before the start of construction, and it will also include any additional bore holes that we do for the pipeline or ancillary facilities prior to the start of construction.

During construction it would include any bore holes put down at that time, plus the significant observations along the ditch.

Q But I take it that that catalogue, whatever its later utility may be, is not going to be available as a design tool?

A It would be available as a design tool with all of the current information in it. At the end of each field program, for example, all of that data would be included in the data retrieval system.

Q I'm sorry, I haven't made myself clear. I understood from your evidence, and the canned evidence, that a detailed catalogue, a geological profile after the ditch has been excavated, will be prepared, and it was indicated in the canned evidence that it would be prepared prior to and during construction. I'm trying to get in between the prior to and the during. I take it's not going to be prepared sufficiently in advance of constuction that it will be a design tool?

A It's under preparation now, as I understand it, so as a matter of convenience to recall, by using a computer, any information we require that is available in a certain area.

Q Apart from bore holes, you don't intend to dig any stretches of trench or dig into the ground as a design tool?

A No, sir, no.

Q I'm concerned about the relationship between the design forces available to you, and the construction forces, and I take it that it's obvious that the responsibility for building the pipeline on the ground is going to lie in the hands in a staff of construction engineers?

A Yes, sir.

Q And that will be an entirely different route than the design engineers?

A My understanding is that the design engineers will have the responsibility to see that their designs are properly implemented.

Q Well, now what does that mean in precise terms? Is this panel going to go out on the route from day to day?

A I would suspect that certain members of this panel will do just that, but there will also be a trained staff, inspection staff, who would be directed by members of this panel, among others.

They would be guided by the Design Change Manual, as well as the design manual.

Q Well, I won't ask for volunteers from the panel to spend that long winter in the north, but do I understand you to say that a design engineering monitoring group is going to be formed?

A The nucleus of this exists now, to ensure the quality control of construction, that our designs are implemented in the manner in which we intended.

In other words, we have the responsibility for the design. We will also have the responsibility to see that they are properly implemented.

Q Well to whom is that group going to report?

A That group would, I believe, report to Canadian Arctic Gas through Northern Engineering.

Q And --

WITNESS HARDY: If I may be of help here, Mr. Scott, this matter has been the subject for discussion in the Board of Directors of N.E.S. Now they have actually had no instruction from Canadian Arctic Gas to proceed with an organization to do the necessary inspection, but they are giving it study. It's not a thing that has been neglected, I can assure you, and it's not going to be a matter of this panel going out and doing the inspection themselves. The situation in terms of manpower will be something comparable to what there is during the design as compared to myself in the old days as a one-man operation attempting to do it.

MR. MARSHALL: Mr. Scott, this area of supervision and control during construction is of course one that can come up with the construction panel and again with the company policy witness we've undertaken to produce at the end of this phase.

MR. SCOTT: It will be dealt with by the construction panel and they will no doubt have their own views about how this design corps of monitors are going to act, and I'll be interested to hear that. I'm also interested to hear how the design group feels this design corps of monitors is going to act. For example, Dr. Clark, if they are dissatisfied with the construction work that the company constructing the pipeline is doing, what are they going to do?

WITNESS CLARK: Well, they

would immediately make known their dissatisfaction in the same way that we do on any other project where we have responsibility for design.

Q To whom?

A Presumably to Canadian Arctic Gas.

Q Well, what I'm concerned about is, have any plans been laid for co-ordinating the construction responsibility and the design supervision responsibility?

A No detailed plans, but we have been told that we have the responsibility to see that our designs are properly implemented.

Q What sort of manpower do you think you're going to have in this design monitoring group?

A That again is under study now and I believe there are some preliminary estimates, but I don't know the figures, Mr. Scott.

Q Does anyone on the panel know the figures?

A I rather doubt it, since this work is going on by other members of our staff while we've been here for the last several weeks.

Q Well, I'm sorry I've kept you in the dark, Dr. Clark.

WITNESS HARDY: Well, Mr. Scott, --

Q Dr. Hardy, do you know?

A As a director of N.E.S. the sort of figure we have been talking about is up the order of several hundred, something like eight or 900 people, and there has been --

Q Monitoring design, is that --

A The increase in staff of N.E.S. to look after the inspection of the construction that they are now designing, and that is under Committee study by N.E.S., despite the fact that they haven't any actual contract to go ahead and recruit this staff; but I personally have given consideration to what the situation will be in the geotechnical end, if we have to provide what we think might be the adequate inspection to be sure that our designs are looked after, you see.

Q What is the estimate as to the number of engineers, Dr. Hardy, that you judge will be required to perform this geotechnical monitoring service?

A Well, the figure, you see at the Committee level, you see, just as almost an eye-ball figure as to what we may need, it could be in the order of 80 or 100, but these are not Ph.D's in the field of geotechnical engineering. These are inspection type staff, plus engineering staff that have the necessary background to supervise the work.

THE COMMISSIONER: Well, Dr. Hardy, you said 800 a minute ago. Now you say 80 or 90, and I gather of this 80 or 90, some may be

engineers and some may be people of lesser qualifications. I don't know whether that's adequate or excessive, but --

A The discrepancy, I think, sir, is that with the 800, that order of figure, that is the manpower requirements that N.E.S. in their first approach, that's Northern Engineering Services, for the complete operation I'm thinking about. Dealing with the geotechnical work, we can see that we might have the order-- it's down around the figure of 80 to 100, you see. In other words, they're pipe inspectors. We would not be providing pipe inspectors. The smaller figure is the people that would be trained to deal with the soil conditions that we need to watch.

Q But you would have people who are not qualified as professional engineers?

A OH yes, yes.

Q Studying soil conditions and inspecting pipe. Now that may be entirely in accordance with good engineering practice, but in any event the figure you gave us, 80 to 100, would include the majority perhaps of people not qualified as professional engineers.

A There would be all grades, you see, and there would be a preponderance of people that are the technician type, or trained specifically for the job. It would be quite unrealistic, you see, to suppose that we could put -- get the number or professional engineers that, if we have

to staff all of these positions, with professional engineers.

Q Oh yes, I understand that.

A There will have to be, this is part of the game of course, but how can you overcome that? I've had some experience with this very thing myself some years ago, and you can actually train a man to do a man to do a specific job.

MR. SCOTT: Well, Dr. Hardy, just so I'll have it clear, and recognizing that the plan is in its opening stages, how many qualified geotechnical engineers do you think are going to be woking or should be working on this pipeline route to do this monitoring work?

A Should be, you say?

Q Yes.

A Well, we would actually take all we could get.

Q Well, how many is all you could get, if there was an unlimited market, what is the number that you need to do the job?

WITNESS CLARK: We have those figures Mr. Scott, but they are not here with us.

Q Well, Dr. Hardy seemed to have some.

WITNESS CLARK: Well, at a broad scale, for instance, we now have in the professional geotechnical staff in the 30's, between 30 and 40 people now.

THE COMMISSIONER: Excuse me, that would include you gentlemen as well?

A Just those of us from Northern Engineering, yes sir.

Q Well, that's about four or five.

A Four of us in the geotechnical area. We have been increasing this --

MR SCOTT: You may have to conscript some of those professors.

A We will be increasing this year, I believe the number is up to about 55. Those will be people that will be working on design and on field work. We have a number of people in the field now on field work, and as we build up and do our field work, we will have a large number of people assigned to field drilling programs and logically these are the same people that will follow through on the inspection. They are familiar with the soils, with the north, with the environment, working on the geotechnical inspection aspect of it.

Q Well, what I am interested in is how many -- and take round figures, if you want, do you think are required to provide inspection by geotechnical engineers as the pipeline is constructed, not while it's being designed or anything like that, but as it's being constructed?

A Well I'm reluctant to take round figures when we have available actual figures

per spread of the people we feel will be required in the field.

Q All right. Well now do you prefer to give the precise figures? I'm grateful for that. I take it that in those precise figures we're going to have a breakdown of the people who are geo-technical engineers and other inspectors.

A Yes.

Q all right, and I take it that the geotechnical engineers who follow construction will be responsible for two things, perhaps among others, the on-site verification of the -- that the work shown in the design drawings is being done --

A Yes.

Q -- and I take it that they will also be responsible for any modification of the configuration of the various designs as is required.

A Yes, working in conjunction with the field engineering supervisory staff.

THE COMMISSIONER: Would this be a convenient time to adjourn for a minute?

MR. SCOTT: If you will give me five minutes I may be finished. There may be some re-examination, I don't know, but --

I suggest, sir, that we have the adjournment now, if that's O.K.

THE COMMISSIONER: All right, we will adjourn for a few minutes.

(PROCEEDINGS ADJOURNED)

(PROCEEDINGS RESUMED PURSUANT TO ADJOURNMENT)

MR. SCOTT:

Q Dr. Clark, just to clear one matter that was dealt with before the break, have we got your assurance that the people who will be doing the modification or clarification of the design as required, as it may be required during construction, will be qualified geotechnical engineers?

A Yes sir, that's our intent.

Q Perhaps with not the same experience in terms of years, but with the same technical qualifications as this panel?

A And perhaps even better.

Q Oh, it boggles the mind.

Dr. McRoberts, the other day I asked you a series of questions about the expected behaviour of the pipe prior to starting, in the event that there was a cracking of frozen ground during the extreme weather. For the purposes of the record, the answer in the transcript contains at page 3433, in Volume XXVII,

Now, we understand that the pipe will, in some circumstances, be installed using controlled flooding, so that in fact in the worst case, the pipe would be completely surrounded by water, frozen water, ice. Does that lead you to make any further comments with respect to your answer?

WITNESS MCROBERTS:

A First of all I did say, I believe I said, in my -- in response to one of your questions, that in fact that was the worst case. We will --

Q And your answer still stands?

A Well, yes. I also point out that the test facility that I mentioned in Alaska, Prudhoe Bay, in that test facility they also flooded the backfill.

Q Well, I read your answer a little differently than you do. Take the worst case, that is the case --

A Perhaps I could see what I said.

MR. MARSHALL: What's the page reference, please, Mr. Scott?

MR. SCOTT: 3433 where the answer is,

"Well, I wouldn't agree with that comment at all. First of all, the amount of load that could be thrown on the pipe is governed by the backfill around the pipe. Now, in the worst conditions that one could conceive of is that the pipe would be completely surrounded by ice. By and large what we would be doing is digging a ditch and putting the native backfill back into the ditch, and/for the time involved prior to

start-up, the pipe would be held, it would be surrounded by loosely compacted backfill that may have thawed and refrozen here and there".

A And then I say,

"In the upper limit, the amount of load that could be transferred wouldn't be, in my estimation, no more than 60 or 70 pounds per square inch".

I am referring to there, line 8 above that, where I say

"Now, in the worst condition that one could conceive of is that the pipe would be completely surrounded by ice".

I qualify that by saying by and large, we wouldn't be surrounding the pipe completely by ice although I do understand as an option we would consider flooding the ditch as a buoyancy control measure.

Q Well let me ask you this: Does your judgment about the situation vary if the pipe is completely surrounded by ice as a result of controlled flooding?

A There's a difference, but -- there's a difference between fully flooded, and non flooded or just native backfill, but even under the worst conditions, I am satisfied that there would be no undue strains thrown on the pipe.

Q All right. Well now, we also understand from some of the evidence that the pipe may, in certain locations which aren't specified,

be bound by restraining hoops which project out from the pipe. The hoops, assuming they may tend to help transfer the forces resulting from the cracking ground. Do you have any comment or does that vary your judgment in any way?

MR. MARSHALL: Mr. Scott, could you refer to some place in the evidence, so that we would have a reference point?

MR. SCOTT: No I can't, but there was evidence earlier given that the pipe would in certain circumstances, we weren't told how frequently they would be placed, be bound by what were called restraining hoops that would project out from the pipe.

MR. MARSHALL: I think you're perhaps referring to evidence that has not yet been given that would be dealt with in the design panel.

MR. SCOTT: Well --

Q Dr. McRoberts, you're familiar with the restraining hoops, are you?

A I think I am, yes.

Q All right.

A I don't see why a hoop around would change the amount of add freeze transferred on a given surface of the pipe.

Q Is it your conclusion then that it won't make any difference to your opinion?

A I still think that insofar as I am aware of the geotechnical implications, I don't

think ice wedge cracking is a problem.

Q Well then the answer is yes?

A Yes.

MR. SCOTT: Mr. Commissioner, with that short exchange, I want to thank the panel for its patience, and those are all the questions I have.

MR. MARSHALL: Mr. Scott will be pleased to hear, sir, that we have no re-examination of this panel.

THE COMMISSIONER: Well, it sounds hard to believe, but it looks as if that is the conclusion of your evidence here, so I would like, Dr. Clark to thank you and all of your colleagues for being so patient with all of us, and we appreciate -- certainly I do very much -- your coming here, and explaining your work in this project to us.

So, thank you very much. If I were you, I would leave before someone else -- someone thinks of something else to ask you.

DR. CLARK: We will take your advice sir, and thank you for your patience.

(WITNESSES ASIDE)

MR. MARSHALL: Sir, perhaps we could have a brief adjournment, before we assemble the next panel. As my learned friend mentioned, they are not all here yet, but we propose to start with

the four who are here and the prepared direct testimony.

THE COMMISSIONER: All right. We will adjourn for a minute.

(PROCEEDINGS ADJOURNED)

(PROCEEDINGS RESUMED PURSUANT TO ADJOURNMENT)

MR. MARSHALL: The panel that will begin giving its evidence now, sir, will deal with the design of the pipeline. As I indicated, there are a number of the members of the panel who will be arriving shortly. We do have four members of the panel, Mr. Hoyt Purcell, Mr. Graham George King, Mr. Carl M. Koskimaki, and Mr. Milton E. Holmberg, and I propose to review their qualifications and and introduce them to you, sir.

HOYT PURCELL,
GRAHAM GEORGE KING,
CARL M. KOSKIMAKI,
MILTON E. HOLMBERG, sworn:

DIRECT EXAMINATION BY MR. MARSHALL:

Q Mr. Purcell, I understand you are the project co-ordinator with Northern Engineering Services Company Limited.

A Yes.

Q And what is your educational background, sir?

A I received a Bachelor of Engineering degree and Mechanical Engineering from McGill University in 1956.

Q Your professional affiliations?

A The Association of Professional Engineers, Geologists and Geophysicists of Alberta; and the American Association of Cost

Engineers.

Q Would you review briefly, sir, your professional experience, from 1956 up to the present?

A In 1956 I worked in the Construction Department of Williams Brothers Company in South America.

In 1958 I joined the Domestic Division of Williams Brothers Company working on natural gas pipeline construction projects. I then went into the office and performed cost estimates, construction cost studies, and some miscellaneous engineering design.

In 1964 I joined the Engineering Division of Williams Brothers Company.

In 1967 I became associated with the Williams Brothers Engineering project of the Great Lakes Gas Transmission Company.

Q What were your responsibilities in that project, sir?

A I was responsible for the preparation of progress reports, capital cost and cash draw-down estimates during construction, and assisting management on special assignments.

Q And what have you been engaged in from 1969 to the present?

A On the project at hand.

Q Sir, what has your overall area of responsibility been?

A I have been responsible for the supervision and direction of mechanical and

systems design for the pipeline, and the assessment of the feasibility of transporting gas from Arctic regions to markets in the south.

Q Thank you, sir. Mr. Graham King, Mr. King, what is your present position with Northern Engineering Services?

WITNESS KING: I'm the manager for the system design group.

Q Do I understand correctly sir, that your educational background is a Bachelor of Science degree in Mathematics from the University of Sidney, Australia, in 1964, and a Bachelor of Engineering degree in Civil Engineering from the University of Sidney in 1966, majoring in fluid mechanics and soil mechanics, and a Master of Engineering & Science Degree in Civil Engineering from the University of Sidney in 1970, again majoring in fluid mechanics?

A That is correct.

Q What professional affiliations do you have, sir?

A I'm a member of the Association of Professional Engineers, Geologists and Geophysicists of Alberta.

Q Turning to your professional experience, sir, is it correct that in 1966 you were research assistant at the University of Sidney?

A Yes.

Q And following '67 and '68 were a post-graduate student at the University of Sidney?

A That is correct.

Q And in 1969?

A I worked as an engineer for the Metropolitan Water Board in Sidney, Australia.

Q When did you join Williams Brothers Canada, sir?

A In 1970.

Q And what have your functions been with Williams Brothers Canada Limited in connection with this project?

A I've been responsible for the flow calculations and the system design of the proposed Canadian Arctic Gas Pipeline.

Q And you have the publications that are listed in the resume that has been circulated. Sir, we'll file with the Inquiry copies of the resumes that pertain to each of the members of this panel, but wait until we've introduced all of them and the whole of the group's resumes can be filed as one exhibit.

You have three publications listed on the second page of that resume, sir.

A That is correct.

Q Mr. Carl Koskimaki, what is your present position with Northern Engineering Services, sir?

WITNESS KOSKIMAKI: I'm senior engineer and supervisor of the mechanical, electrical and local control design of the compressor stations.

Q Sir, you hold a B.Sc.

degree in Engineering Science from Montana College, of Mineral Science & Technology.

A That's correct.

Q That you obtained in 1965.

A Yes.

Q And your professional experience from 1965 to 1971 was with Mountain Fuel Supply Company.

A Yes sir.

Q What responsibility did you have there, sir?

A Gas engineer with duties including system flow studies, compressor station design, cost estimating, construction and special design studies.

Q You joined Williams Brothers Canada Limited in 1971, sir?

A Yes sir.

Q And what has your position been from November, 1972 to the present?

A Senior engineer and supervisor for the Northern Engineering Services Company Limited.

Q Thank you. The fourth gentleman on the panel, Mr. Commissioner, is Mr. Milton Holmberg, Mr. Holmberg, you are the president of Metallurgical Consultants Incorporated?

WITNESS HOLMBERG: Yes, that is correct.

Q And you received a B.Sc.

in Metallurgical Engineering from Pennsylvania State College in 1931.

A Yes.

Q Could you list, sir, your professional affiliations and honors?

A American Society for Metals; American Welding Society; American Society for Testing+Materials; National Association of Corrosion Engineers; American Petroleum Institute; American Society of Mechanical Engineers; Fellow of the American Society of Metals.

Q Yes sir. Would you review briefly your professional experience from 1932 to '36? I understand that you commenced as a metallurgist and welding engineer with Black, Sybils & Brice of Oklahoma City.

A That is correct.

Q And what did your work involve there, sir?

A My work initially involved laboratory work, chemical analysis, mechanical testing, metallographic examinations, and later I was transferred to the shop, working on special welding problems.

Q Now from 1936 to 1951, sir, I understand that you were a metallurgical engineer for Phillips Petroleum Company?

A Yes, I went with Phillips in 1936, and helped them set up a metallurgical laboratory.

Q What were your responsibilities there, sir?

A Initially, I was involved with inspection of pressure vessels, pipes, valves and other equipment, and later worked with the construction division on welding problems, and actually operated the metallurgical laboratory in the role of making investigations of failures of equipment.

Q Mr. Holmberg, from 1951 to the present, you have been an independent metallurgical consultant?

A Yes.

Q What work have you been involved in throughout this period, sir?

A I have been involved in the study of the performance of metals and their effective use, inorder to prevent failures in service, consulting work is included. In the early 1960's, developing specifications for and the inspection of

large diameter pipe for several large gas pipeline projects, work on high pressure LPG lines and a helium pipeline for Williams Brothers. I prepared specifications for the pipe laid in a 42 inch diameter oil pipeline in Iran in 1964. Following completion of this project, I was retained by Iranian Oil Services to set up a test program and make extensive strain gauge studies on pipe to which was -- these studies were representative of repairs and the attachment of fieldfittings.

In 1966, I was requested by Williams Brothers to check the source of steel intended to be used by Stelco for the manufacture of the 36 O.D. pipe for the Great Lakes Project.

In 1966 I also prepared the specifications for Grade X60 pipe for use by the National Iranian Oil Company to build a 700 mile 42 inch O.D. gas pipeline from the southern part of Iran to the Russian border. This project required the necessity to specify steel for use at temperatures down to minus/10 degrees Centigrade.

I have been consultant to the Canadian Arctic Gas Project since 1969.

Q Sir, you have published those articles that are listed in Appendix A to your resume?

A Yes.

Q And what has your area of responsibility been as a consultant to the Arctic Gas project?

A I have been a consultant to Northern Engineering Services Limited and the Metallurgical Sub-committee. I helped in the preparation of pipe, valve, fittings and welding and related specifications.

Q Thank you, sir.

Mr. Commissioner, in response to the preliminary rulings, a list of reports and studies upon which the panel may rely or to which they may refer, has been prepared and circulated, and I propose to file that list of reports as the next exhibit.

(LIST OF REPORTS FILED EXHIBIT 104)

MR. MARSHALL:

Q Mr. Purcell, I understand that your panel is responsible for the presentation of the evidence to the mechanical design of the application which was prepared under your overall supervision and direction?

WITNESS PURCELL:

A Yes, we are responsible for the following sections of Section 8, Location, Design and Capacity of Facilities.

8(b)(1), system configuration and design.

.1 Summary of projected gas volumes by years and expansion for throughput increase;

.2 System Configuration.

.4.1 Codes, Standards and Regulations;

.4.2 Pipeline (except the portion entitled "Buried Line Stability", for which the geotechnical panel is responsible);

.4.3 Compressor and Gas Measurement Stations (except the parts on architectural design and pads, and foundations, for which the geotechnical panel is responsible);

.4.7 Corrosion Control.

8.b.2 Formulae and Basic Assumptions.

8.b.3 Facilities Design and Capacity - Drawings (except those design drawings related to typical equipment and building foundations and to river crossings for which the geotechical panel is responsible)

8.b.4 Flow Diagrams.

8.b. 5 System Capability Analysis

8.b.6 Material Specifications

8.b.7 Communications and Supervisory Control

Q Would you briefly describe each of these sections, sir?

A Section 8.b.1.1 "Summary of Projected Gas Volumes by Years", lists gas volumes for each segment of the proposed system, on an average day basis by operating year and on an annual basis by

calendar year. The supply volumes by year were provided by Canadian Arctic Gas; the Systems Design Group of Northern Engineering Services provided the fuel consumption estimates. This section also contains a tabulation of the compression and gas-chilling equipment proposed to transport the projected gas volumes.

Section 8.b.1.2 "System Configuration", describes the considerations that led to the selection of the pipe sizes, compressor station sizes and spacing and gas chilling and cooling processes that the design is based on.

In Section 8.b.1.4.2, the portion entitled "Metallurgy and Stress Analysis" discusses the design temperature criteria that were used in the metallurgical design and lists the basic criteria of system performance that were considered in the stress analyses. The portion entitled "Appurtenances and Facility Crossings" describes briefly the designs of mainlline block valves, scraper traps and road and railroad crossings.

Section 8.b.1.4.3 "Compressor and Gas Measurement Stations" sets forth the design criteria and describes the design of these facilities. This section includes a discussion of the emissions from the stations and the noise levels to be expected.

Section 8.b.1.4.7 "Corrosion Control" summarizes the conclusion of studies into the corrosion aspects of the pipeline system and describes the proposed means to control corrosion

on the varous portions of the system.

Section 8.b.2 "Formulae and Basic Assumptions", lists the equations that were used to calculate gas properties, pressure drop in the pipeline, gas temperatures, and compressor, chilling and cooling station service requirements. It then lists the assumptions upon which the system was designed and its performance determined.

Section 8.b.3 "Facilities Design and Capacity Drawings", contains design drawings for the various facilities proposed.

Section 8.b.4 "Flow Diagrams" shows salient details of the performance of the system when operating at maximum capacity (that is, with all equipment in service) under average summer and average winter conditions, for each of the first five operating years.

Section 8.b.5 "System Capability analysis" sets forth an estimate of the gas volumes that could be delivered from the system in each operating year, when considering the reduction in throughput that will be experienced when equipment is out of service for maintenance or other reasons. This estimate was prepared on the assumption that neither the producers' gas processing plants nor the connecting pipeline systems would impose supply or delivery limitations on the combined facilities of Alaskan Arctic Gas and Canadian Arctic Gas.

Section 8b.6. "Material Specifications" contains three specifications for

large diameter pipe and one specification each for 16 inch and larger valves and 12 inch and larger fittings.

Section 8.b.7 "Communications and Supervisory Control " discusses the communications requirements for constructing and operating the pipeline, and how the requirements are proposed to be implemented.

The panel adopts the statements made in the sections of the Application just referred to.

Q Sir, I understand that there is an errata pertaining to Section 8(b) and Mr. Commissioner, we have prepared a list of the errata, and I propose to file that as the next exhibit.

(ERRATA FILED EXHIBIT 105)

MR. MARSHALL: Please delineate your areas of responsibility with respect to the pipeline project.

A I was supervisor of the mechanical and systems design group and the preparation of design for this project. Our general instructions from the project sponsors, which were developed in part on the basis of studies we performed, included the points of gas supply and delivery, the gas composition and the design gas volumes for each operating year.

In addition to the information and instructions given us by the sponsors, information had to be acquired from other groups within Northern Engineering before the design group could proceed with its task. The pipeline route is the primary example of such information. Other such information included the feasibility of potential sites for compressor stations and other ancillary facilities, soil temperatures and properties, geothermal calculations to allow us to develop and verify the heat transfer calculation techniques used in our flow studies, and logistical and construction limitations on design. Parametric studies were made that were concerned with the comparative economics of various pipe and compressor station sizes.

We also had to acquire construction costs for the alternatives being considered before we could compete the studies.

I established three major objectives for the design group. The first was to develop technically correct engineering designs for those areas for which I was responsible, which would demonstrate to the sponsors, potential financial backers of the project and regulatory agencies, that the system would perform satisfactorily from an engineering point of view (and which would provide an adequate basis for making cost estimates). The second was that present day technology should be used. We were not to consider in the design future technological advances which might take place. The third objective was that the pipeline system should be an optimum design so that it could be built and operated to transport gas at the minimum unit cost.

Q /To What level of detail has the design been carried at this point?

A We have carried the design to the level that satisfies the first objective mentioned above, that of providing a basis for adequate cost estimates and demonstrating satisfactory performance. The other two objectives provided guidlines for reaching this first objective. We selected representative types of major equipment such as turbines, and determined their performance requirements so that estimating prices could be secured from the manufacturers. We prepared material specifications, discussed them in detail with manufacturers of pipe,

valves, fittings and pressure vessels, and satisfied ourselves of the availability of these components.

We have performed analyses which are unusually rigorous for this stage of design so that we could be confident of making accurate predictions of the performance of the pipeline system in view of this scale and environmental considerations. Our stress analyses have gone into considerable detail for the same reasons. We investigated procedures for hydrostatically testing the pipeline so that we can demonstrate the feasibility of the project in this regard.

In brief, we have performed the work that is conventionally required to support the engineering aspects of a pipeline application before regulatory bodies, and have also attempted to anticipate any potential problems as a result of the project's scale and environmental setting that could affect the project's feasibility or impact.

Q What additional work remains to be done before the project can be constructed?

A In our areas of responsibility, most of the remaining work is concerned with the specific selection of equipment and materials to be used in the construction of the facilities. This selection involves a process of preparing detailed specifications for each material item, soliciting information from one or more manufacturers of each item, evaluating the responses, and making purchasing recommendations to our client based on relevant factors such as the engineering

concerns of availability and suitability for the intended service.

This process commences with the major items of material, such as the turbine-compressor units, and continues down through progressively smaller items until nuts and bolts are reached. This is because all the services at a compressor station, for example, including lube oil, fuel and starting gas systems, etc., are dependent on the requirements of the major equipment. Another obvious example is that buildings cannot be finally selected until the size of the equipment is precisely determined, and foundation design cannot be completed until the equipment and buildings have been selected.

While the equipment is being selected, we will commence the preparation of design drawings so that the various facilities can be constructed properly. These are scale drawings showing the precise arrangement and dimensions of all the facilities down to the smallest details.

Before the pipeline can be hydrostatically tested, it will be necessary to develop a detailed testing plan that literally considers the pipeline route on a foot by foot basis. This plan will include the elevation profile of the route, the location of each water source and disposal point, the direction in which each test section will be filled with water and dewatered, the sequence of testing and the location and final design of the test headers, the pressure-retaining devices installed temporarily

on both ends of each test section.

Q Can you tell us why this final design work has not been completed at this time?

A First, we do not believe it is necessary to perform designs at this level of detail in order to demonstrate that we have met the objective of demonstrating satisfactory performance and providing a basis for adequate cost estimates.

Second, if a final design were complete at this time it would not reflect conditions that might be imposed by regulatory bodies, or changes resulting from the completion of gas transportation contracts.

Third, the cost of final design would be prohibitive for the project's sponsors at the time, as it would be risk money, spent before any assurances were received that regulatory approvals would be forthcoming.

There are other aspects of final design not within this panel's responsibility that must be done. Primary among them is the acquisition of further soil information along the pipeline route so foundations can be designed once the equipment is selected, river crossings can be finally engineered, and the specific designs for maintaining the stability of the pipeline and the adjacent right-of-way can be designed.

Q Do any of the objectives of the design group require you to relate the pipeline to its environment?

A Pipeline engineers have a particular interest in stability and security and a concern for the physical environment is involved in these factors. In this sense our design objectives include the preservation of the integrity of the physical environment. In general, the steps necessary to provide for the integrity of the pipeline also are required to protect the physical environment.

Q What were the responsibilities of the design group?

A Generally, this group was responsible for the following:

1. Systems design. The determination of the locations and performance requirements for the compressor stations; system flow calculations to determine the performance of the system under various operating conditions; thermodynamic studies to determine the heat flow around the pipeline and the required duty of the chilling and cooling facilities; and the determination of the necessary gas specifications and the properites and behaviour of the gas.

2. Pipeline design. The mechanical design of and material cost estimates for the pipeline including: mainline block valve assemblies, scraper trap assemblies, river crossing manifolds, sales taps and measurement stations; proof testing, which includes the selection of test media and the determination of procedures for hydrostatically proof testing the pipeline; and estimates of material costs.

3. Metallurgy. Co-ordinatiion of the considerations

given to the megallurgical aspects of the project, including preparation of specifications,field welding, bending, and mill inspection procédures.

4. Stress analysis. Mechanical stress analysis of the pipeline, compressor stations and operating appurtenances.

5. Station design. The mechanical, electrical and local control design of and the material cost estimates for the compressor and chilling stations; and the selection of optimum station sizes.

6. Corrosion. The development of an effective plan to control corrosion of the pipeline.

7. Communications. The design of and material cost estimates for the communications and supervisory control system.

The group's responsibility did not include route selection, geotechnical design, civil design (station pads, air strips, foundations, waste disposal), investment cost estimates, logistics or scheduling.

MR. MARSHALL; Mr. Commissioner, I believe the remaining four members of the panel have arrived and I'd like to add them now and introduce them to you and review their qualifications

THE COMMISSIONER: Yes. Certainly, we'll just break informally for a minute or two, if you want to have them seated.

MR. MARSHALL: Thank you verv much.

(PROCEEDINGS ADJOURNED FOR FEW MINUTES)
(PROCEEDINGS RESUMED PURSUANT TO ADJOURNMENT)

MR. MARSHALL: Mr.Commissioner, the four additional members of the panel are Mr. Cameron Reid, Dr. Patrick Price, Mr. John McMullen and Mr. Kenneth Rathje.

Beginning with Mr. Cameron Reid, I would like to read his qualifications.

Q Mr. Reid, your present position is that of supervisor of Pipeline Mechanical Design of Northern Engineering Services?

A That's right.

Q And what is your educational background, sir?

A I have a Bachelor of Engineering Degree from the Royal Military College. I received my degree in 1967.

Q That's Kingston, Ontario?

A Yes, sir.

Q And what professional affiliations do you hold, sir?

A I am a registered Professional Engineer in Alberta and Ontario, and I'm a Member of the Canadian Society of Mechanical Engineering.

Q Following your graduation from R.M.C. in 1967, I understand that you remained with the service?

A Yes sir, I was in the Royal Canadian Corps of Signals from 1967 to 1970 as a Signal Officer.

Q And from 19670 to 1971,

you were with Dupont of Canada?

A Yes, sir.

Q What were your responsibilities there?

A I was a design engineer responsible for cost estimating, design and construction supervision for small projects on the plant.

Q From 1971 to the present, you've been with Williams Brothers Canada Limited?

A Yes, sir. And it's successor, Northern Engineering.

Q What area of responsibility have you had, sir, in connection with this project?

A I've been involved with the proof testing, the preliminary design of pipeline appurtenances, and gas measurement facilities and the dense-phase pipeline alternative.

Q Thank you.

Dr. Price, what is your present position with Northern Engineering Services?

WITNESS PRICE:

A In charge of the stress analysis there sir.

Q I will see if I can help you. You are, as I understand it, senior engineer and supervisor of Mechanical Stress Analysis?

A That is right, sir.

Q And your educational background is that you have a Bachelor of Science in Civil Engineering and Master of Science in Civil Engineering from the University of Witwaterstrand

in South Africa?

A That is correct.

Q With degrees obtained in 1965 and 1967 respectively?

A That's correct.

Q You received your Ph.D. from the University of Calgary in 1972?

A Correct.

Q You received certain awards; in 1965, the Andrew Roberts Post Graduate Scholarship, and the Roberts Construction Company Prize in Civil Engineering and the South African Federation of Civil Engineering Contractors Award, is that correct?

A Yes.

Q And from 1968 to 1971 you were on a National Research Council of Canada scholarship?

A That is right.

Q Your professional affiliations, sir, include the Association of Professional Engineers, Geologists and Geophysicists of Alberta? Is that correct?

a That is correct.

Q And you're an Associate Member of the American Society of Civil Engineers?

A That is correct.

Q Your professional experience, beginning in 1966, was firstly as a research and development engineer for Brickor (Pty) Ltd. in South Africa?

A That is right.

Q 1967 you were a lecturer in structural engineering in Johannesburg?

A That is right.

Q From 1967 to 1970, you were research assistant at the University of Calgary?

A That is right.

Q And from 1971 to '72, you were a Post Doctoral Fellow, Numerical Analysis and Systems Analysis?

A That is correct.

Q Where was that, sir?

A The University of Calgary.

Q And when did you become involved in the Arctic Gas Project, sir?

A In early 1973,'I think it was.

Q Your involvement has been in the field of stress analysis, sir, has it from the outset?

A Correction, sir, it was in 1972 that I became involved in the Arctic Gas pipeline project.

Q Could you speak more closely into the microphone? I have difficulty hearing you.

A 1972 sir I became involved in the Arctic Gas Project.

Q And your involvement has throughout been in connection with stress analysis?

A That is right.

Q And you have to your credit the publications listed in the second page of your resume?

A That is correct, sir.

MR. MARSHALL: Thank you, Dr. Price.

Mr. John McMullen.

Q Mr. McMullen, I understand you were the senior design engineer with Northern Engineering Services?

WITNESS MCMULLEN:

A Yes, sir.

Q What is your educational background, sir?

A I hold a Bachelor of Science degree from the University of Alberta in electrical engineering.

Q Which you received in what year, sir?

A 1962.

Q And what professional affiliations do you hold?

A I'm a registered professional engineer in the Province of Alberta.

Q Following graduation, sir, I understand that you joined Alberta Government Telephones, and that you held a number of positions with A.G.T. from 1962 to 1971?

A That is correct, sir.

Q Could you just review

briefly the various positions and the responsibilities that they entail?

A In 1962 I began as an engineer in training with Alberta Government Telephones. Work included working on contracts and specifications for tendering in the designing of microwave radio systems. In 1964 I became an engineer Class 2 and began my work in transmission requirements for microwave systems.

In 1965, I was promoted to Standards Engineer, involved with somewhat the same work.

In 1969, I became supervisor engineer of Transmission Standards.

Q And in 1971 you joined Datap Systems Limited which I understand is involved with Williams Brothers?

A Yes, Datap Systems Limited is a wholly owned subsidiary of Williams Brothers Canada Limited.

Q What responsibilities did you hold, firstly with Datap Systems and then with the Northern Engineering Services Company Limited?

A I was responsible for feasibility studies involving communications and supervisory controls for the Arctic Gas Pipeline.

MR. MARSHALL: Thank you, sir.

Mr. Kenneth Rathje.

Q Mr. Rathje, I understand that your position is that of Corrosion Engineer with Northern Engineering Services Company Limited?

WITNESS RATHJE:

A Yes, sir.

Q Would you outline your educational background, sir?

A I received a Bachelor of Science Degree in mechanical engineering at the University of Okahoma in 1969.

Q Have you taken courses that specifically relate to corrosion matters?

A Yes, I have taken the National Association of Corrosion Engineers basic corrosion course in Calgary in 1971, and in 1973 I took a cathodic protection technology course in Houston, Texas.

Q What professional affiliations do you hold, sir?

A I'm a member of the Association of Professional Engineers of Alberta, and I am a Member of the Engineering Institute of Canada, and the National Association of Corrosion Engineers and the American Society of Mechanical Enginers.

Q Would you review briefly, your professional experience since graduation, sir?

A Yes. I began with Rangeland Pipeline, which is a division of Hudson's Bay Oil and Gas. With that firm I was a pipeline engineer.

I was responsible for various aspects of construction, inspection of construction, and I became involved with their communications system, and I also was involved in economic designs and preliminary designs for additional pump station.

In 1971 I joined Williams Brothers Canada Limited. From that point on I was involved with corrosion work.

Q What have your duties included with Williams Brothers and then Northern Engineering Services, sir?

A I was responsible for coating tests, coating cost estimates, cathodic protection studies and other corrosion related tasks in connection with the Arctic Gas pipeline.

MR. MARSHALL: Thank you, Mr. Rathje.

Mr. Commissioner, I would like to file the resumes for the panel as the next exhibit.

(RESUMES FILED AS EXHIBIT 105)

J.J. MCMULLEN
C.M. REID
P. ST. J. PRICE
K.E. RATHJE, Sworn:

DIRECT EXAMINATION BY MR. MARSHALL:

MR. MARSHALL: Mr. Commissioner,

Miss Hutchinson was to stand at my shoulder and nudge me when she wanted them sworn. The witnesses have stated their qualifications prior to their being administered the oath, and I would like to have them simply confirm that the qualifications that they have stated are correct.

Mr. Rathje?

WITNESS RATHJE: Yes.

MR. MARSHALL: Mr. Koskimaki?

WITNESS KOSKIMAKI: Yes.

MR. MARSHALL: Mr. King?

WITNESS KING: Yes.

MR. MARSHALL: Mr. Purcell?

WITNESS PURCEL: Yes, sir.

MR. MARSHALL: Mr. Holmberg?

WITNESS HOLMBERG: Yes.

MR. MARSHALL: Mr. Reid?

WITNESS REID: Yes, sir.

MR. MARSHALL: Dr. Price?

WITNESS PRICE: Yes.

MR. MARSHALL: Mr. McMullen?

WITNESS MCMULLEN: Yes, sir.

MR. MARSHALL: We will continue then sir, Mr. Purcell -- I believe we were on page 10 of the prepared direct evidence.

Q In designing this pipeline, what special design considerations had to be taken into account?

WITNESS PURCELL:

A Firstly, we had to take

into account special considerations related to the scale of the project, that is the large diameter, high operating pressure and high gas volumes.

Secondly, there are special considerations related to the arctic environment of much of the pipeline. Some special considerations related to a combination of both the large scale and the Arctic environment.

Q Would you please explain how your design has taken into account special design considerations related to the scale of the project?

A The scale of the project has required special consideration with respect to the flowing gas temperature behaviour and stress levels in the pipe. Considerable experience has been built up for the design and analysis of the performance of 36 inch and smaller diameter pipelines.

These pipelines have typically transported less than one billion cubic feet daily, and have not usually required gas chilling or cooling stations at the discharge of compressor stations to control the temperature within desirable limits.

For 36 inch and smaller diameter pipelines, actual operating experience, particularly with regard to flowing temperatures has been of considerable value and design in the prediction of performance , but our work has shown that long, large diameter pipelines transporting more than two billion cubic feet daily, cannot be operated without using gas chillers or coolers.

We found that without chillers or coolers, the large blocks of horsepower required at each station to transport the large volumes of gas would increase the temperature differential between the ground and the gas so that the flowing temperature would tend to increase from station to station and exceed practical limits. The installation of cooling stations on the downstream side of each compressor station therefore has been incorporated in the design.

I will discuss the stress level considerations later in the testimony under the heading, "Stress Analysis".

Q Please explain what special design considerations are presented by the permafrost environment?

A Such considerations related to the need to maintain the permafrost along the right-of-way. The metallurgical and gas composition constraints that result from the necessarily low-flowing temperature, the metallurgical considerations that relate to/low air temperatures in the north, and pipeline stresses. For more than 1,000 miles of its route the pipeline passes through areas of permanently frozen ground. Some of the permanently frozen ground contains excess ice which can cause the ground to become unstable and easily erodible if it thaws. In order to stabilize the right-of-way and thereby maintain the integrity of the pipeline, we propose to operate the pipeline at temperatures generally lower than the ground temperature .

To maintain the gas flowing temperature below the ground temperature it is necessary to remove the energy imparted to the gas during compression, plus the heat flow from the ground to the gas. To do this we have adopted a technique commonly used in the gas-processing industry, a closed cycle mechanical refrigeration system using propane as the refrigerant, which we call a chilling station. Each compressor station in the permafrost region incorporates a chilling station immediately downstream of the compressor, so that the temperature of the gas entering the ground downstream of the station can be controlled at the

appropriate level. These chilling stations are to be powered by gas turbines and will dispose of the energy removed from the gas by cooling the propane refrigerant in air-cooled heat exchangers. The low flowing gas temperatures require special metallurgical considerations for the pipe steel. A design temperature of minus ten degrees Fahrenheit was specified for pipe to be installed in the northern portions of the pipeline system. This design temperature provides a margin of safety against the minimum flowing temperature expected in the system, which is approximately zero degrees Fahrenheit under normal operating conditions. The gas temperature will be maintained above minus ten degrees Fahrenheit under any operating condition, by minimum suction temperature, over-ride controls that will cut back on the compression horsepower if the gas temperature approaches minus ten degrees F.

The low gas temperatures have also been considered in determining the composition of the gas. The presence of heavy hydrocarbon components inthe gas can cause formation of hydrocarbon liquids at low temperatures and pressures, and the existence of hydrocarbon liquids in the gas stream can cause difficulties in operating the gas compression equipment. Laboratory tests were therefore conducted to confirm that the gas compositions proposed by the Prudhoe Bay and Mackenzie Delta gas producers would not result in the formation of hydrocarbon liquids in the gas pipeline.

Q If I can interrupt there,

perhaps Mr. King could explain what gas hydrates are.

WITNESS KING: A gas hydrate is a mixture of gas and ice crystals. Looks very much like snow.

Q Carry on, Mr. Purcell.

WITNESS PURCELL: Likewise the formation of gas hydrates is more likely at low temperatures and hydrates may block the pipeline or restrict the amount of gas that the pipeline can carry. Accordingly, laboratory tests are being conducted to determine the critical water content specification for the pipeline gas such that hydrates will not be a problem.

The unusually low ambient temperatures were also considered in the metallurgical design. For those components of the pipeline system that can be expected to reach or be exposed to ambient temperatures, we specified a design temperature at least as low as those ambient temperatures.

In the mechanical stress analysis we had to take into account the possible pipe movements due to causes such as frost heave and settlement, so that over-straining and buckling of the pipe would not occur.

Q Would you please explain the design considerations arising from the combination of the scale of the project and its Arctic environment?

A Both the scale of the project and its Arctic environment give rise to design considerations in the areas of the technology of pipe, valves and fittings, pressure testing the pipeline,

coating materials and field welding.

We have solicited test data from manufacturers of pipe, valves and fittings and have determined from such data that the capacity and technology are available to meet our design specifications.

Special consideration was given to the procedures for hydrostatically testing the pipeline in the permafrost regions. Two test methods are proposed: Warm water, which is commonly used in Southern Canada to test pipelines constructed during the winter; and a methanol-water solution whose freezing point is low enough to avoid the formation of ice in the pipe during the test. In this investigation, we performed studies to determine the thermal regime inside and outside the pipe during the various hydrostatic testing operations with these two media. Other groups investigated the environmental and geotechnical effects of testing and we are confident that the pipeline can be safely tested.

In order to determine the suitability of pipeline external coating materials for use in permafrost, we performed laboratory tests designed to simulate the service conditions that would be encountered. On the basis of the results of these tests and our experience with various coating systems we have determined that depending upon the installation season and the operating temperatures, several coating systems are suitable for the various portions of the pipeline system. We also determined through tests

that our Arctic test facilities that it is feasible to provide cathodic protection for pipeline buried in permafrost.

In view of the low ambient temperatures under which the welding along much of the route will be performed and the heavy sections to be welded, our material specifications are designed to ensure weldable components and we have in hand the preparation of field welding procedure specifications.

Q So we clearly understand what is included in your responsibility, sir, what is meant by "mechanical design"?

A In this context, it means the arrangement of equipment (valves, for example), and the associated piping and fittings to produce a facility that will perform a desired function. Examples of such facilities for the pipeline are scraper traps, valve settings, and gas measurement stations. It excludes the detailed metallurgical considerations and the design of the foundations and buildings.

Q Are there any features of these facilities that are unusual or unique?

A Except for their size, these facilities are conventional. Their design follows well proven precedents in the gas transmission industry. Data we have secured from manufacturers demonstrate that components of this size are available.

Q How will the pipeline be tested ?

A The pipeline will be hydrostatically tested after construction to prove its strength and integrity. The length of pipe tested will vary with each test, but in most cases will be between 3 and 10 miles.

A hydrostatic test consists of welding pressure retaining test heads on each end of the test section, filling the test section with water, and pumping water into the test section to increase the internal pressure to at least 125% of the planned operating presure. The test presure is maintained for a period of time sufficient to ensure that there are no small leaks or defects, and then the pressure is relieved and the water removed.

In addition, it is proposed to run electronic pigs through the pipeline designed to detect any injurious defects not previously detected and in particular those that may have occurred during construction.

Q How do you solve the problem of potential freezing of the water inside the pipe?

A That problem is not unique to this pipeline, but in permafrost the ground temperatures at pipeline depth during hydrostatic testing will require that either an anti-freeze such as methanol be added to the water, or a technique known

as warm water testing be used. Warm Water testing involves heating the water to about 50 degrees Fahrenheit before pumping it into the pipe. The warmwater heats the backfill and eliminates the risk of freezing for a limited time. Both methods will be used on this pipeline with water anti-freeze testing being the predominant method used north of the 60th Parallel.

Q Would you outline the details of a water anti-freeze testing plan?

A Methanol is considered as the most likely anti-freeze choice. The methanol would be barged to a storage site near the pipeline right-of-way during the summer prior to construction and would be stored in bladder-type storage tanks within a diked storage area. At the start of testing it would be moved to the test-site, mixed with water, and pumped into the pipe. The mixture would remain in the pipe and would be used in testing subsequent sections until testing was completed and the solution was ready for disposal.

Q How will this testing fluid be disposed of?

A Two methods of disposal are possible. The first consists of diluting the test medium and disposing of the solution. The alternative method is to distill the solution and recover the methanol. This process would yield a solution of about 1% methanol by weight, which could then be disposed of. The methanol-rich distillate, of about 70% methanol

by weight would be suitable for disposal by burning, or it could be recovered for secondary use. The distillation process would result in the release of less than 2% of the total quantity of methanol.

MR. MARSHALL: Mr. Commissioner, Mr. Reid has prepared some slides which help to better illustrate the proof-testing the pipeline. I would ask him now to present those.

WITNESS REID:

A As mentioned previously, the hydrostatic testing of a pipe is conducted after the pipe has been constructed and backfilled, but consists of tapping or sealing the ends of the test section with a test head, filling the test section with the liquid test medium, pressurizing the test section by means of injecting additional test medium with a high pressure pump, scaling the section and monitoring the pressure for a specified period of time to ensure that there are no leaks, and finally releasing the pressure and removing the test medium from the test section.

Should a leak be discovered at any time during the hydrostatic test, the pressure is relieved, the leak repaired and a complete retest is conducted.

The conventional method of testing winter construction in non-permafrost areas is a technique known as warm water testing. This schematic represents how the water is obtained and heated. We have here a water source, a fill pump. A portion of the water is removed, passed through a heater and remixed with the main stream, yielding a water with a temperature of about 50 degrees Fahrenheit. This then goes to the test section and is introduced into the test section.

This schematic represents a warm water test section. Water from the heater enters the test section and passes through the test section

until the test section has filled. Then for an additional period of time, sometimes referred to as the circulation time, warm water is continued to be pumped through the test sections, thus warming the backfill until the temperature of the water being discharged reaches the specified temperature somewhat above 32 degrees Fahrenheit. This can be as high as 40 or 45 degrees Fahrenheit.

The amount of water reqired to warm the backfill sufficiently to conduct a hydrostatic test without any freezing is dependent upon the length of the test section, the temperature, the type of backfill, the fill rate and water temperature.

There are a number of disadvantages to the warm water test method which include highwater usage, and the creation of a thaw bulb around the pipe.

As an example, for a five mile test section in the Norman Wells region, the quantity of water required to test the section would be about two and a quarter times the fill volume of the test section. The thaw bulb created around the fill end of the test section would be about three inches from the pipe wall, the thaw front.

Because of the disadvantagesof the warm water test method, a test method known as water methanol testing is proposed for use on this pipeline. Again, a water source is required and methanol is required. The two are mixed and then introduced into the test section. A quantity of water

methanol mixture in excess of that required to fill a test section is mixed and the additional fluid passes into the subsequent test section.

After all the methanol has been used in making the mix, the test section is then ready to be sealed off and a hydrostatic test conducted.

After the first hydrostatic test has been conducted, the test fluid is then pushed from the tested section by means of compressed air into the subsequent test section, again with excess test medium going on into the following test section.

It should be noted that no additional water source is required. I believe the previous slide explained the length of these test sections as being approximately three miles.

The same test medium is used to conduct all the test sections in a spread. The end of the testing season the, test fluid must be disposed of. This schematic represents the process by which distillation would occur and the methanol can be separated from the test solution.

The source of test fluid comes from the last test section. It passes through a heat recovery exchanger and into boilers and into a distillation column. The distillation column would yield two streams. Bottoms which would be a one percent waste water -- one percent methanol waste water solution, which is suitable for dispersal onto land and ice over water.

The distillates would be a methanol

rich solution of about 70 percent methanol. This would go to tankage and be suitable for disposal by burning.

This next slide shows how tested sections are joined in a manner which ensures that the entire pipeline is of the same -- has been subjected to the same rigorous testing. After two adjacent test sections have been successfully tested, the test heads are removed and the sections are used -- are joined, using a pretested section of pipe.

This pretested pipe has been subjected to a hydrostatic test similar to that given the test section. The welds used in making the connections are inspected by x-ray to ensure their soundness.

Previously in my presentation, I mentioned the removal of water from the test section and the introduction of water. This is done using a tool commonly referred to as a pig. This schematic shows a pig which is specifically designed for the removal of water from that test section. The pig is propelled by high pressure gas or air behind it. And the four cups act as squeegees, pushing the water ahead of it.

Should any water bypass any one of these squeegees, this particular pig, has a feature which allows the water which passes a cup to get ahead of the cup through this passage, the high pressure gas providing the mode of force to move the water back ahead of the pig.

I now have three slides which I think will also be of interest. I may not have -- the last schematic I showed you represented a pig which was designed for the removal of water from the test sections. This slide shows three pigs, these are 56 inch pigs, which were manufactured for a gas pipeline in Russia. These pigs could be used for either filling or dewatering a test section to separate the test fluid from the air in the line, or the air being used to dewater the line.

MR. MARSHALL: Where were these pigs made?

A These were manufactured in the United Kingdom.

In my presentation I made reference to test heads which are welded to the end of test sections to maintain the pressure and allow the introduction or removal of water and the introduction or removal of pigs or pigging devices.

This particular slide shows a 48 inch test head which was used on Interprovincial Pipeline's 48 inch oil line. The valves on the top of the test head are used for introducing or removing water and the arrangement on the end, is actually closure which can be opened to introduce or remove a pigging device.

In his testimony, Mr. Purcell made reference to an electronic internal inspection tool, or an electronic pig which would be used prior to testing, to detect primarily any faults that may

occur during the construction of the pipeline.

This is a picture of a 36 inch tool, as Mr. Purcell described, developed by Trans-Canada Pipelines. This device is run prior to testing and can detect construction defects. This would be used to ensure that the possibility of a failure during hydrostatic tests is reduced to a minimum.

Q Mr. Reid, is this what they call a smart pig?

A Yes, this is often referred to as a smart pig.

Q I had to get that in the record.

A That's all I have.

MR. MARSHALL: Thank you, Mr. Reid.

THE COMMISSIONER: Thank you, Mr. Reid.

Q Now, to the subject of metallurgy, sir. What aspects of the pipe are of particular interest from the metallurgical viewpoint?

WITNESS PURCELL: The Metallurgical Sub-Committee developed the specifications for pipe and welding. The specifications for pipe and welding comply with the applicable codes and regulations and contain additional requirements for this pipeline that have been developed in the course of our metallurgical studies. In developing the specifications, the primary metallurgical concerns were:

1. Mechanical properites, particularly low temperature notch toughness.

(i) Transition temperature below the design temperature for all mainline pipe to avoid brittle fractures.

(ii) High notch toughness at the design temperature to avoid fracture initiation.

(iii) The use of mechanical reinforcing bands on main-line pipe to positively assure the arrest of propagating sheer fractures.

2. Weldability.

(i) Seam weld quality, particularly high notch toughness of weld metal and heat-affected zone at low design temperatures.

(ii) Girth weld quality , in addition to high notch toughness of the weld in heat-affected zone at low design temperatures, the pipe's composition and carbon equivalent, the filler metal and the elimination of defects that might initiate failures.

Q Sir, which are the seam welds?

A The seam welds are the welds that are put in in the process of manufacturing the pipe.

Q And the girth welds?

A The girth welds are made in the field to join the sections of pipe together.

Q Could you now discuss brittle fracture?

A There are two aspects of brittle fracture that are of concern. One concern is whether the pipe material is susceptible to brittle fracture propagation. The second concern is that pipe material also changes from ductile to brittle behaviour in the initiation of a fracture. Brittle fractures propagate at speeds faster than the rate at which the pipe depressurizes and therefore the fracture might continue for long distances. When the material is susceptible to brittle fracture initiation, small flaws can initiate failures.

The change from ductile to brittle fracture is a function of temperature. The mainline pipe material will be deisgned not to be susceptible to brittle fracture propagation. For a given material, the change from ductile to brittle fracture initiation occurs at a temperature that is significantly below the change for fracture propagation. Therefore, the mainline pipe material will not be

subject to brittle fracture initiation either. For the heavy wall pipe, the fracture initiation transition temperature will be below the lowest expected operating temperature to ensure that brittle fracture initiation cannot occur.

THE COMMISSIONER: Excuse me, Dr. Purcell. By "the heavy wall pipe" do you mean the mainline pipe, don't you?

A No sir. By that I mean the heavier yet wall pipe that would be used at compressor stations or at river crossings.

THE COMMISSIONER: I see.

MR. MARSHALL: Mr. Commissioner, Mr. Holmberg has prepared some slides and graphs that will help take us through this rather difficult subject area, and I would ask him now to make his presentation.

WITNESS HOLMBERG: The purpose of this presentation is to explain how metals behave, why and how they break, and discuss some of the tests and names used to prevent failure.

Metals break in three ways, either in a brittle manner, a ductile manner, or a combination of the two. To help understand what is meant by brittle, I'll show the first slide. These are two tensile test specimens, a standard type of test that is made. The sample at the right is broken with very little evidence of ductility, any evidence of stretching, deformation. It's almost a square break. That is a brittle break, it shows very little evidence

of deformation. The sample at the right, however, has stretched, reduced in section, and has failed after considerable plastic deformation. That is referred to as a ductile type fracture.

Q That's the fracture on the left, is it, sir?

A On the left, yes.

THE COMMISSIONER: Brittle on the left; ductile on the left.

A Yes.

Q We're with you.

A Now in order to better understand why metal breaks in these two different manners, a little knowledge of metallurgy will be of some help. Metals are crystaline materials. They are made up of a mixture of crystals, and in the individual crystals or grains, the atoms are arranged in an orderly way. In steel, the atoms are arranged so that they form tubes, and the next slide --

Q They form what?

A Tubes. T-U-B-E-S. Sorry. Perhaps this slide will better illustrate it. This is a simplified drawing showing the arrangements of atoms on one plain. If this were in three dimensions this would be a cube. In the single plain the atoms are arranged in this square shaped arrangement and I'd like to call attention to two types of plains that exist, a cleavage plain in which it is perpendicular to the lines of force between the atoms, and then sheer

plains that are diagonal. These two different plains play an important part as to how metals fail. Now if this crystal were loaded, in tension, the two ends are shown here, in the cleavage plain direction the metals -- the atoms are pulled apart a slight amount; whereas in the cleavage plain direction they slip along these plains and become distorted. Now if you would remove the tensile load, both of these would return to this position here, and this is what we had when we were using metals in the elastic limit. When you load them up and unload them they return to their original position without getting deformation.

The next slide shows what happens, illustrates what happens when you continue loading. Now the sheer plains are weaker than the bonds between the atoms, with the result that normally when you load a piece of steel it tends to start failing in sheer, or deforming in sheer, I should say, in which case the slippage that was shown on the previous slide continues further so that a whole block, this block of atoms here, actually move up and then re-align themselves with the atoms across the sheer plain. You unload this sample here after it's been strained to this point, it will not return to its original position but will remain as shown here. This is, results in the plastic deformation that was shown in that tensile specimen.

On the other hand, if the material cannot move along these plains, you reach a

point that you can break the bonds between the atoms and you'll get a cleavage break and this will result in the brittle type failure that was shown in the one tensile test specimen. Now the way the strength of steel is increased is by principally by putting blockages in the sheer plains so that movement will not take place. As a result, the sheer strength increases and you increase the tendency to get this cleavage, brittle type of failure.

Now this, it is possible to retain the same degree of ductility and toughness in steels, even though you increase their strength, up to limits of about 150,000 pounds per square inch. This is well below the strength levels which we're using steels in this pipeline. Now if you lower the temperature of steel as well as other metals, you reduce the tendency for a sheer type of failure to take place and the material will deform in a ductile manner, and increase the likelihood of this to occur. By making tests over a series -- over a wide range of temperatures this tendency can be shown and there are a large number of different types of tests that can be used to determine this transition from a ductile behaviour to a brittle behaviour. I should point out that the abscissa here shows an increase in temperature and vertical component shows an increase in ductility.

Now, it should be noted that this change from ductile to brittle behaviour does not take place at a specific temperature. It takes place over a range of temperatures, and the shape and steepness of this curve varies, depending upon the type of test used, the speed of testing, the size of the specimens used and several other variables.

The next slide illustrates one way of plotting such a curve. This is a series of tests made at temperatures zero, twenty, thirty, forty and sixty degrees. At sixty degrees, this specimen broke with a ductile fracture, this small area here, a small brittle zone at the initiation of failure in this particular test.

At forty degrees, there is a slight increase in this brittle zone. At thirty degrees, a still greater increase and 20, further, and at zero degrees, it is essentially a hundred percent brittle. I hope I went through this right, the increase in brittle zone.

This particular series of test the transition zone would be between about 40 degrees and zero degrees. This is a test that's been developed and been used widely in the -- to check the transition temperatures, or the transition zone of pipeline steels and a useful transition temperature which is really a defined temperature within the transition zone is the temperature at which you have 85 percent, or 80 percent shear fracture. This would be referred to as an 80 percent shear fracture transition

temperature.

It's been found that this transition temperature corresponds with the behaviour of line pipe at different temperatures. There have been other transition temperatures defined, for example, the fractures of ships during the war; it was found that the behaviour ofthe Charpy v-notch impact test corresponded with the behaviour of the type of steels that were used in ships, and they developed what they call the 15 foot pound energy transition temperature.

One of the important things to keep in mind as far as these transition temperatures, and the difference between a ductile and brittle fracture is that a brittle fracture occurs very quickly, where as this deformation that was shown in one of the earlier slides requires time and takes place more slowly. This is quite important, and the work done by the Battelle Memorial Institute for the American Gas Association showed that brittle fractures occurred at very high speeds; ductile fractures on the other hand occurred at low speed, this being speed plotted in this ordinate.

And as would be imagined between the two extremes, why there is an intermediate zone. The difference in the speeds, between the different types of fractures as illustrated in this slide here. Now the brittle fractures occur from about 1,500 feet per second up to about 3,000 feet per second.

Now this is faster than the acoustic velocity of the gas which ranges from about 1250 to 1450 feet per second. And the significance of this is that in a brittle fract-ure/it propagates so fast that the advancing crack is always or continues to be exposed to the pressure that existed at the time the failure originated. In other words, there is no loss of energy as far as the crack, rapidly propagating crack is concerned.

Now, on the other hand, shear failures propagate at a much lower rate, down in the order of about 400 to 700 feet per second, well below this speed of gas, and the highest speed that's been recorded to date is something like 1,100 psi, or a hundred feet per second.

Now, the significance of this is, that in a ductile fracture the advancing crack is exposed to decreasing pressures, so the likelihood of it propagating for long distances and -- is much less than in a brittle fracture.

THE COMMISSIONER: With a brittle fracture you don't get depressurization because of the speed of the fracture?

A That's right, that's right. With a ductile fracture you do get the pressurization.

Just a few words about some of the tests that are used. The most commonly used test is to check the behaviour of steel is what they call the Charpy v-notch test. This is a small specimen,

0.394 inches square with a 45 degree notch in one side. It is placed in a suitable holder and then a pendulum swings down and hits the specimen and breaks it.

Now, the energy that is absorbed in breaking the specimen is the most common measure of the -- used in evaluating this specimen. This is in --the energy is in foot pounds which is equivalent to the length of the arm of the pendulum times the weight of the pendulum, and for example if you had a 40 foot pounds, it would be 40 foot pounds to break this small section.

Now, this is the same as if you had a one pound weight and raised it up 40 feet and dropped it down and broke the specimen.

Now, we are interested in the transverse properties of line pipe because of the hoop stresses and the tendency for the, if the failure occurs, the fracture propagating in a longitudinal direction. As a result, the test specimen is orientated in that direction.

Now, there are several other ways of evaluating this test, one is the shear area that was previously referred to; another is measuring the amount of deformation that occurs.

One of the disadvantages of the Charpy V-notch test is its small size. Battelle, in its work on studying brittle fracture, found that it was desirable to test specimens with the full fitness of the pipe, so this thickness here represents the thickness of the pipe. It's a larger specimen,

three inches, and again has a notch which is pressed in with the idea of initiating a brittle fracture. The specimen is broken by a heavy weight dropping and hitting the specimen with enough force to cause it to snap in two.

Now one of the other advantages of this specimen is that it's wide enough that you not only initiate a fracture here, but the tests propagate across about three inches, something less than three inches. This is desirable in correlating the tests with the fracture speeds and behaviour of line pipe.

The next slide compares the -- these two sizes of the samples and the advantages of the larger specimen. I think it is somewhat obvious.

The comments so far have been made with respect to fractures initiated at high speeds. Now, there are many failures that occur at just a static space or constant pressure. There is no impact or high loading rate. These types of tests require different types of specimens, and one of the more useful is a test that's been developed in rather recent years and used extensively over in England. I've been principally responsible for developing this specimen.

The specimen is considerably larger and it has a very sharp crack, or notch at the bottom, and before testing the specimen, an actual crack is developed at the root of this notch. This is done by flexing the specimen at high

speeds and specific loads until you develop what they call a fatigue crack. Now this gives an extremely sharp notch and is the type of thing that we are interested in as far as the behaviour of defects in pipe are concerned.

After the notch is developed the specimen is supported in two supports, and then a known load applied, and the amount of opening of this crack is measured by the special gauges. By means of this test it is possible to determine the point, the loads at which cracks are initiated. It's also possible to make this type of test over a range of temperatures and develop a temperature transition approach.

Now the reason that notches are so important is that many steels will behave in a ductile manner, while you have uniform sections. But in the presence of a notch they will behave in a brittle manner, and this is important because of the crack is the most serious defect you can have in a piece of steel, and it's important to work up these correlations between the behaviour of notched steel and actual behaviour in service.

Now in specifying the materials for the pipeline we have under consideration, we have taken into consideration all these factors and worked with the suppliers of equipment to make sure that steels will be available suitable for the temperature ranges and conditions that we'll encounter, and have conducted numerous tests to check performance of the materials under conditions that we will be encountering. As a result, we believe we're prepared to specify materials that will result in a safe pipeline that will be compatible with its environment.

Q Thank you, Mr. Holmberg.

Mr. Commissioner, Mr. Holmberg has brought a couple of specimens which he could show to you to illustrate these two types of fractures.

THE COMMISSIONER: Mr. Holmberg showed me those specimens, the rest of you couldn't hear what he was saying, but the specimens are so small you really have to stand up close to examine them, and when we adjourn at six Mr. Holmberg perhaps wouldn't mind showing the counsel and any others those same specimens and explaining the test.

Carry on, Mr. Marshall.

MR. MARSHALL: Thank you, sir.

Q Mr. Purcell, to continue then with your direct testimony.

WITNESS PURCELL: The effect of low temperatures causing brittle fractures in steel is quite well understood as a result of extensive work done by our industry throughout the world during the past 30 years or more. Research work sponsored by the American Gas Association at Battelle Memorial Institute since 1953 has resulted in the development of the Drop Weight Tear Test whereby it can be determined whether or not line pipe is susceptible to brittle fracture propagation. However, the Battelle work on line pipe was limited mostly to thicknesses in the order of one-half inch and temperatures down to 32 degrees Fahrenheit. The Arctic Gas Pipeline involves the use of thicker steels and exposure to lower temperatures. It was not known to what extent the

the drop weight tear test procedure for determining the transition temperature between ductile and brittle fracture propagation was applicable to these more severe conditions. A test program was set up by which the validity of the drop weight tear test for the project's steel could be evaluated.

The results of the test program showed that the drop weight tear test is a conservative predicatorof the full-scale brittle to ductile propagation transition behaviour of the 0.72-inch wall thickness mainline pipe. For the 1.25-inch heavy wall pipe, however, the avoidance of brittle fracture initiation is the main consideration. This pipe is used in short lengths primarily at compressor stations, and therefore could not be subject to a long failure even in the brittle fracture propagation mode. The test program confirmed that the methods developed to calculate critical crack sizes for boththe mainline pipe and the heavy wall pipe are accurate. The high notch toughness of all pipe results in a critical crack size so large that the cracks can be readily detected during fabrication and in service.

Q Please describe how you plan to avoid fracture initiation.

A Fractures always initiate at defects, where the streeses are magnified due to the geometry of the defect. The size and type of defects that can exist without initiating a fracture are related to the pipe size and the strength and toughness of the steel and the stress. As the pipe diameter, wall thickness and toughness of the pipe increase, the size of

a tolerable defect also increases. For the pipe in our system, a through-wall defect sufficiently long to initiate a failure is much larger than the defects that our inspection procedures are able to detect.

THE COMMISSIONER: Excuse me. Let me just read that again. Yes, I understand.

A The standard solution to the problem is to detect and eliminate these defects during the pipe manufacturing process, and to employ good transportation practices, construction inspection procedures, and a stringent in-place hydrostatic test, so that defects large enough to initiate fractures will not exist when the pipeline is placed in operation. We believe that our stringent inspection procedures, combined with the large size of a critical defect, and the use of electronic pigs practically eliminate the risk of a critical defect existing in the Arctic Gas Pipeline when it is placed into operation. It is also necessary to protect against such a defect being introduced into the pipeline after it goes into operation. The two primary causes of post-construction defects are damage by external forces and corrosion. Surveillance of the pipeline is necessary to prevent the first. Our experience should be better than industry's average over much of the route because of the limited humid activity and the presence of frozen ground in the north. We believe that damage from corrosion will also be minimal because of careful protection, and the low temperatures over much of the route. Again, the long

defect necessary to initiate a fracture in this pipeline is a great advantage.

Q Please describe how you plan to limit the length of any propagating fractures which might occur in mainline pipe.

A The propagation of brittle fractures in mainline pipe is prevented by the use of pipe made from steel with the ductile/brittle propagation transition temperature below the operating temperature so that in the unlikely event a fracture develops it will be a ductile type fracture. Ductile shear fractures propagate at slower speeds than brittle fractures and are therefore less likely to be as long. Experience has been that when a propagating brittle fracture changes to a ductile type, the fracture terminates within a short distance. However, in recent years a few ductile type fractures up to about 1000 feet in length have been experienced.

This precipitated a large amount of work at Battelle. The results of this work enabled Battelle to develop a hypothesis by which they could determine the notch toughness requirements of the steel necessary to prevent unstable (long running) ductile shear type fractures. Battelle's work explains how fractures speed, material properites, and design parameters determine fracture arrest capabilities in a given length of pipe.

MR. MARSHALL: Let me just stop you there for a moment. There has been mention

made a number of times of Battelle. Could you or perhaps Mr. Holmberg explain who or what Battelle is?

A I think Mr. Holmberg has been working with them for longer than I have.

WITNESS HOLMBERG: Battelle is an organization in Columbus, Ohio, that was founded by a man obviously by the name of Battelle, to enable organizations to have research work done in metallurgy. They were founded back about 1930, and any organization or any individual or company has an opportunity to use their services, at a price. They have built up a very competent and extensive organization to do research work on all phases of metallurgy, as well as many other fields now. They have been very useful, particularly during the war and some of the other developments where special materials were required. They did a large amount of work on the brittle fracture of steels in ships and other problems.

Q Thank you, sir.

WITNESS PURCELL: After reviewing and evaluating the development of the Battelle hypothesis, we used it as the basis for our original investigations of the notch touchness requirements for the mainline pipe to control ductile fracture propagation. The fracture control criteria developed by Battelle had been shown to be accurate for pipe in the sizes and strengths being used in the natural gas pipeline industry. It was considered important nevertheless to conduct full-scale burst tests to check and confirm

whether the fracture control criteria based on the Battelle hypothesis would be accurate for pipe specified for the project.

Canadian Arctic Gas has conducted three tests on 48-inch by 0.720-inch Grade 70 pipe, manufactured in compliance with its specifications. These tests were conducted at temperatures and pressures close to those contemplated for the proposed pipeline system. In addition, predecessor study groups each sponsored two tests. These four earlier tests were conducted at conventional temperatures on pipe with lesser wall thicknesses than the pipe now proposed.

Q What did the tests show?

A The test showed that the fracture arrest behaviour of the proposed main line pipe at the design temperature and pressure cannot be consistently predicted by the Battell hypothesis.

Therefore, our design is based on adding mechanical reinforcing bands or similar devices at suitable spacings along the pipeline to assure control over the length of the possible fracture. Three separate tests made to date show that reinforcing bands can be used in the remote/event of a fracture, to control the length of fracture.

In none of our tests did a fracture propagate through a reinforcing band. As stated earlier, we also specify a notch toughness sufficiently high that a defect would have to be very severe before it would initiate a crack, and we can find defects much smaller than this with our inspection procedures.

We specify other tests to ensure that brittle fracture initiation and propagation will not occur.

Q Have you satisfied yourself that steels suitable to this pipeline are commercially available?

A Yes. The steel industry was advised of our concern for good mechanical properties, especially notch toughness for the project. Because of the size of the project and large tonnages of steel that will be required, the steel industry was justified in doing extensive research work, and effective liaison

was maintained with the individual steel companies as well as the industry as a whole.

This resulted in the development of commercial quality steels which meet our design criteria.

Q Please discuss the weldability of the pipe?

A First, seam weld quality. Our pipe specifications require the same minimum notch toughness for the seam weld as they do for the pipe. These welding problems and their requirements have been discussed and reviewed with the steel industry and the manufacturers of welding electrodes and equipment. The steel industry and pipe mills did a large amount of work in developing weldable steels and developing welding procedures for the manufacture of the pipe, and provided extensive test data on the seam welds to us. These data show that the project specifications can be met.

Second, girth weld quality. As the pipe will be joined in the field by welding, girth weld quality was likewise a consideration, especially since much of the field welding will be performed at low atmospheric temperatures.

Arctic Gas recognized that the steels used in making the pipe must be suitable for welding, both with respect to the manufacture of the pipe and installation in the field. The compositions of the steel were therefore limited to assure weldable steels.

Investigation of automatic welding

and of manual welding processes was undertaken by Arctic Gas which had numerous meetings with leading welding rod manufacturers from the United States, Canada, Europe and Japan, and with several companies developing automatic welding processes. After the companies had an opportunity to develop electrodes and equipment that they believed suitable, plate and pipe were submitted to the companies for their use in the further tests and development work. The companies then submitted their recommendations for rods and procedures for evaluation by Arctic Gas. Welds are presently being made and will be evaluated by several laboratories. We are confident that this program will be effective and that field welding will not present any unusual problems.

THE COMMISSIONER: Dr. Purcell, before you go on; am I to take it that Arctic Gas is considering automatic welding as well as manual welding procedures? I take it automatic welding is what the word implies?

A Yes, my understanding is that the welding procedure that was contemplated when the application was drawn up was manual welding.

Q Yes.

A Because at that time it could be demonstrated that it could be done, but the automatic welding provides generally more uniform quality and possibly lower costs and it's being investigated as an alternative.

Q Just so there's no misunderstanding, you have some kind of automatic welding machine, do you, when you undertake automatic welding?

A Yes, sir.

MR. MARSHALL:

Q Perhaps to clarify, you or perhaps Mr. Holmberg,could describe the type of equipment that's used in automatic welding?

WITNESS HOLMBERG:

A There have been several automatic welding machines developed. One has been used especially rather extensively. These machines operate using gas for shielding. They use fine wire for the filler metal, and the machine is mounted on the pipe and has a small welding heads that move around the pipe in sequence, making the welds.

This equipment has been used on pipelines now, various types, for probably four or more years, being used especially extensively in off-shore operations where high speed welding is desirable, and I understand one of these machines are now being used on the Alyeska line, I'm not just sure what the status there is.

THE COMMISSIONER: Well they haven't begun laying pipe in the Alyeska line as yet, have they?

A No, they are planning to use it, and I understand are using it for some of the double jointing.

I might correct myself a little bit

on that too. There is going to be some storage facilities made, using pipe, in which they plan to, as I understand it, plan to test this equipment out further on some of that work.

Q That's Aleyeska?

A Alyeska.

MR. MARSHALL:

Q Sir, could you explain what is meant by the term "fittings," or perhaps one of your panel?

WITNESS PURCELL:

A Mr. Reid has done most of the work on the fittings.

WITNESS REID:

A A fitting would be a steel component which allows, usually allows two or more pipes to be joined in a manner other than a straight line.

A fitting would be used at a branch connection or to allow the piping system to turn a sharp corner, or to end off a piping system.

Q Thank you. Would you please discuss the metallurgy of valves and fittings?

WITNESS PURCELL:

A Valves and fittings include sections with greater thicknesses than the pipe. The toughness requirements for valves, fittings and flanges are aimed at preventing fracture initiation since the length of propagation is limited by the size of the part. A toughness level and inspection procedures

are then specified such that any defect remaining in the part after final inspection and hydrostatic testing is much smaller than the critical defect size at the most severe operating conditions.

Q Please discuss metallurgical aspects of pipe bending?

A The straining of the metal associated with bending affects its mechanical properties, and it was considered adviseable to make tests to determine the extent of the effect. Such studies can best be made by laboratory tests. A contract was therefore let to the University of Alberta to conduct these tests. Their studies show that the properties of the bent pipe are consistent with the design criteria of the pipeline.

Q Turning now to the subject of stress analysis, sir, what special design considerations have been taken into account in the structural design of the pipeline?

A We had to take into account three special considerations related to the scale of the project and the permafrost environment of much of the pipeline:

(1) Forces which are resisted by the soil at buried field bends in pipelines would be large for the proposed pipeline due to its size. These forces are caused by restraint to longitudinal expansion or contraction of the pipe steel due to temperature changes and by gas pressure. As a result of these forces, movements of pipe will occur at the

bends. The solution to this phenomenon is to establish limitations on bend angles to protect against wrinkling at field bends during operation of the pipeline and to prevent excessive bearing pressures in the soil.

Parametric studies of the interaction between structural response of the pipeline and the surrounding backfill and ditch wall for overbend, sidebend and sagbend configurations were undertaken. These studies used temperature and pressure loadings expected along the route and geotechnical inputs provided by the geotechnical study groups.

(2) The potential for frost heaving exists in a number of areas where the pipeline would be operated at temperatures below 32 degrees Fahrenheit. Differential frost heaving would impose bending in the pipe in these regions. We have established maximum allowable curvature changes in the pipe, which were provided to the Geotechnical Group for use in their designs.

(3) The pipeline route passes through areas of generally low seismic activity. Nevertheless, special work was done to develop seismic design criteria and recommendations for the earthquake resistant design of the pipeline system.

We undertook stress analyses using loadings caused by earthquake motions in combination with other design loadings such as those caused by gas pressure and temperature differentials.

The results of these analyses indicate that stresses caused by earthquake motions are relatively small and will not pose a problem.

MR. MARSHALL: Mr. Commissioner, Dr. Price has prepared some slides and graphs to help deal with this question of the loadings that a pipeline can be subjected to, and I would ask him now to make that presentation.

Dr. Price is attempting to recover from the flu and a cold, and he has lost part of his voice so we will have to bear with him.

WITNESS PRICE: The purpose of this presentation, sir, is to explain the stress analysis and the basis for changing curvature criteria which has been discussed previously. The stress analysis is concerned with stresses and strains that will be imposed in the pipe by various loading conditions and with the stability of the pipeline. The loading conditions considered include gas pressure, temperature differential, earthquake motions, and a number of conditions which will locally bend and change the curvature of the pipe. These include differential frost heave, differential settlement, point uplift or also support and movements at field bends.

To help demonstrate the significance of the wrinkling and stability I will deal with a few simple concepts and then get into it. First of all consider a simple spring suspending like that. If a load is applied to the end of the spring, we extend its length, it will extend in tension and increase in length; on removal of the load the spring returns to its original length.

If an increasing load is applied to the spring, a graph of load versus extension can be drawn. This will typically be a straight line. The extension of the spring is therefore proportional to the applied load and the reversability if the load is removed, in other words it

moves that to zero again.

Let us consider the case of a steel bar to which we will do the same thing. Suppose the bar is loaded with a tension of a load shown there, this load imposes a tensile stress in the bar which is equal to the load divided by the area, the steel, that is the cross- sectional area up there. As with the spring, the load will cause the bar to extend, the strain is defined as the extension divided by the original length of the bar that is the extension of D divided by L.

The strain is used instead of an absolute extension because it is independent of length and for a given stress would be the same for all lengths of the bar, so we are just making this whole system dimensional. As a result of the extension, the bar will tend to contract laterally as well as shown here, and the dotted line there depicts that contraction.

A graph of stress versus strain may be drawn as shown on the sketch for steels of the type to be used in the pipeline, this graph has an initial elastic range. However, at a certain stress called the portional limit, the graph starts to bend over and reduces in slope with increasing load application. The specified minimum use strength is a material specification for pipeline steel. That is defined as the stress at an 0.5% strain.

This, is determined, is required,

the specified property of the steel is determined using a specified test. After passing the specified minimum yield strength, we enter into what is known as the strain hardening range and the steel can be stressed a great deal more until it eventually breaks at a strain of around 30 to 40%. The ultimate tensile strength is defined as the maximum measured strength in the test which the curve was developed from.

The only ultimate tensile strength, the stress appears to decrease in the engineering graph of stress versus strain, and the steel eventually breaks. The measured strain, is as I pointed out, in the order of 30 to 40%. That level of strain is normally referred to as the ductility of the steel which is a sort of broad term which defines the ability of steel to deform under load.

A portion of the stress strain curve, this is of interest in the stress analysis, that is where strain is less than about 1 or 2% is drawn here. Suppose I'll just describe some mechanical properties of the steel, suppose the bar is loaded up to the proportional limit and the load is then removed or returned back to zero, and the strain will reverse as shown there. However, if the stress or the load is increased beyond the proportional limit up to, say this point here, we would have some strain hardening in the steel, and if this load is now removed, the recovery will be down, the elastic would be down this line here. We would have a

residual plastic strain imposed on the steel which I have illustrated here.

THE COMMISSIONER: You say that if you -- if the load that is applied is great enough, the steel will be less elastic thereafter, is that what you're saying?

A That is correct, for continuing increase in that load.

Q Does that increase the -- or does that lessen the resistance of the steel to a brittle type fracture?

A Not really, no sir. I'm not really concerned with the fracture aspects here. Fracture, brittle fracture in a bare bar of this type would occur under a really low temperature which is called a fracture initiation transition temperature. A premature fracture would occur if you had a flaw or a ductile fracture, that is.

Q Well, excuse me, forgive me for interrupting you, but when you get what you describe, I think, as plastic strain --

A M-hm.

Q -- which results from the load that is applied being beyond the proportional limit, when you get that you have altered the quality of the steel, I take it.

A Somewhat, yes. I'll be getting onto that.

WITNESS HOLMBERG: May I say

a word? I don't think we should say that we lowered the quality of the steel.

THE COMMISSIONER: I said "altered".

A Oh, altered, yes, you've altered the quality of the steel very slightly. What you've done is actually increased the strength a small amount, you have used up a very small amount of the ductility, almost an insignificant amount, but the steel continues to behave just the same as it did before, but that the elastic limit has been slightly increased, and we'd say the yield point has been slightly increased.

Q I'm just trying to --

A This is something that happens every time you take a piece of steel and form it, for example, you take a flat plate and form it into a pipe. You are exceeding the elastic limit and getting this plastic deformation that we talked about before, and in a sense creating a new set of properties, as far as the steel is concerned. This is the reason that we measure our properties on the finished pipe, not on the plate that goes into it.

THE COMMISSIONER: Yes, yes, I understand that. Well, it looks as if you've got some formulae there, Dr. Price, and we've had trouble with those before. All of these gentlmen here have to have some understanding of what you're talking about, and perhaps I could ask them, is this all sinking in or is it

heading above you and hitting the back of the room somewhere?

MR. SCOTT: Who are you going to begin with, Mr. Commissioner?

THE COMMISSIONER: Do you speak for everyone?

MR. SCOTT: I will have to read the transcript, I am afraid.

THE COMMISSIONER: Well, I was going to say that this is fairly heavy going. That's no reflection on you, Dr. Price, it's obviously difficult material. I wonder if, since we're getting close to the hour of adjournment, Mr. Marshall, if there is any way of making it a little easier to comprehend? I'm obviously not wholly taking it in. The members of your panel would regard that as an under-statement, I'm sure, but --

MR. MARSHALL: Well, perhaps, sir, given the hour, we might adjourn and come back fresh in the morning with hopefully a simplified version of this presentation that would make some of these things a little easier for all of us.

THE COMMISSIONER: Well, this group of eager students over here on the left, I think --

WITNESS PRICE: They went.

THE COMMISSIONER: Well, we'll adjourn, Dr. Price, and don't let anyone lead you to believe this is any reflection on your prodigolic

capacity, it's difficult stuff and I'm afraid we're difficult students, so see what you can do overnight, Mr. Marshall, and we'll adjourn until nine in the morning.

(PROCEEDINGS ADJOURNED TO APRIL 15, 1975)

MACKENZIE VALLEY PIPELINE INQUIRY

IN THE MATTER OF AN APPLICATION BY CANADIAN ARCTIC GAS PIPELINE LIMITED FOR A RIGHT-OF-WAY THAT MIGHT BE GRANTED ACROSS CROWN LANDS WITHIN THE YUKON TERRITORY AND THE NORTHWEST TERRITORIES FOR THE PURPOSE OF THE PROPOSED MACKENZIE VALLEY PIPELINE

and

IN THE MATTER OF THE SOCIAL, ENVIRONMENTAL AND ECONOMIC IMPACT REGIONALLY OF THE CONSTRUCTION, OPERATION AND SUBSEQUENT ABANDONMENT OF THE ABOVE PROPOSED PIPELINE

(Before the Honourable Mr. Justice Berger, Commissioner)

Yellowknife, N.W.T.

April 15, 1975

PROCEEDINGS AT INQUIRY

VOLUME XXX

APPEARANCES:

Mr. Ian G. Scott, Q.C. Mr. Stephen T. Goudge, Mr. Alick Ryder and Mr. Ian Roland	for Mackenzie Valley Pipeline Inquiry;
Mr. Pierre Genest, Q.C. Mr. Jack Marshall, Mr. Darryl Carter and Mr. John Steeves	for Canadian Arctic Gas Pipeline Limited;
Mr. Reginald Gibbs, Q.C. Mr. Alan Hollingworth	for Foothills Pipelines Ltd.;
Mr. Russell Anthony, and Prof. Alastair Lucas	for Canadian Arctic Resources Committee;
Mr. Glen W. Bell and Mr. Gerry Sutton	For Northwest Territories Indian Brotherhood and Metis Association of the Northwest Territories;
Miss Lesley Lane	for Inuit Tapirisat of Canada and The Committee for Original Peoples' Entitlement;
Mr. Ron Veale and Mr. Allen Lueck,	for Council for Yukon Indians
Mr. Carson H. Templeton,	for Environm ental Protection Board;
Mr. David Reesor,	for Northwest Territories Association of Municipalities;
Mr. Murray Sigler,	for Northwest Territories Chamber of Commerce.

I N D E X

Yellowknife, N.W.T.
April 15, 1975

(PROCEEDINGS RESUMED PURSUANT TO ADJOURNMENT)

MR. GIBBS: Mr. Commissioner, it appears not too optimistic to say that my turn for cross-examination might come this morning.

During the course of it, I will be asking the witnesses to refer to a portion of the Canadian Arctic Gas Pipeline filing which has not yet been marked as an Exhibit. It may be that those who want to follow the references to the volume will want to equip themselves with it before cross-examination starts.

I expect that Mr. Marshall has something to say about marking it as an exhibit, but we would meet that when it comes.

The document is entitled "National Economic Effects of the Applicant's Proposal", Section I4b, and it's -- and it's also entitled "Second Supplement to the Application of Canadian Arctic Gas Pipeline Limited", and was executed where else but Toronto, on January 23rd, 1975.

THE COMMISSIONER: Thank you, Mr. Gibbs.

MR. MARSHALL: We left off yesterday, sir, with Dr. Price. He was making a presentation dealing with the various loadings on the pipe. He's back again in better health, and carry on with his presentation.

THE COMMISSIONER: Fine, fine.

HOYT PURCELL
GRAHAM GEORGE KING
CARL M. KOSKIMAKI
MILTON E. HOLMBERG
JOHN T. MCMULLEN
PATRICK S.T.J. PRICE
KENNETH E. RATHJE
CAMERON M. REID, Resumed:

DIRECT EXAMINATION BY MR. MARSHALL, CONTINUED:

WITNESS PRICE:

A What I want to do this morning, sir, is show you some slides of some tests which were undertaken at the University of California and these will demonstrate what wrinkle looks like and what we are doing is the stress annalysis.

As I mentioned yesterday, the loads that we consider are the pressure, the temperature differential and bending due to various effects, which include frost heave, settlements, and movements of bends.

After I show you these slides of these tests, I will go into a number of applications with some simple little drawings and show you their significance in the field.

Before we get onto that however, I would just like to go back to this stress strain curve we went onto yesterday, and just clarify a few points.

As I mentioned, this is a bar loaded in uni-axle tension and I define the strain merely as the extension divided by its original length and the stress is merely a load divided by the cross-sectional area of the bar. That's just the definition of these quantities.

Now, if they load this bar up to the elastic range curve, in this range here, and at the proportional limit will bend over if you like. The elasticity decreases or the stiffness decreases and it is easier to extend the bar and the curve flattens off. The steels for the pipeline are designed or required, are specified to have, to be able to extend a great deal before they eventually reach the ultimate tensile stress where it will eventually break. This range of strain is known as the ductility.

The point I am trying to get across is the pipeline steel will be ductile for static loading conditions. A brittle material, brittle failure occurs in tension condition.

Brittle failure will normally occur within this region here. Now a pipeline is subject to stresses in the hoops -- hoop direction which is due to the pressure, hoop stress, and to longitudinal stresses due to pressure and temperature differentials.

A buried pipeline is restrained so it is normally in compression underground, and you don't worry about brittle failure in compression. What you worry about is what is known as instability, and that is wrinkling or overall bucking of a column, for example, that sort of effect.

THE COMMISSIONER: That's something that you said was owing to the pressure ?

A The actual compression?

Q No, I'm sorry. You said that with a pipeline you worry about wrinkling and buckling.

A Right.

Q Did you say -- I don't know whether I heard you correctly -- did you say that was owing to pressure?

A This effect is caused by an actual compression load, which is developed in the pipe by gas pressure, longitudinal effect, and by temperature differential. A temperature differential is a change in the pipe steel from the time that it's installed in the ditch to a maximum operating gas temperature or minimum temperature, it varies. Of course the pipeline is restrained, it can't expand and a compressive force comes up and if it's too much you get this sort of effect.

Now some full-scale tests were undertaken at the University of California for the Aleyeska Pipeline Company on 48-inch diameter pipe. Here is a schematic drawing of the test arrangement; the pipe is approximately 30 feet, I think. It is loaded with the actual load to simulate the pressure and the temperature differential effects imposes an actual, along there, a compressive stress in the pipe and was also subjected to internal pressure, high pressure, the normal pipeline application. The actual loads were

then applied to bend this pipe and the strains and curvature changes associated with this work with each application of load were measured.

Q Just before you tell us about this test, was the pipe that was tested the same pipe that has been specified for the Arctic Gas Line through Canada?

A No sir, it had a lower specified minimum yield stress and a smaller wall thickness.

Q Whatever that pipe, in terms of stress and strain, whatever it was able to resist, you would be able to say for the Arctic Gas pipe, is that correct?

A There is strong evidence to suggest that the thicker wall thickness of our pipe for any given diameter can take a larger amount of bending before it wrinkles. Now, here is the test configuration as the loading frame in which the pipe was mounted and the actual load applied.

Q Excuse me. Can you gentlemen see this? If you can't -- can you see what -- all right, they can all see, apparently.

A Here is the formation -- the initial formation of a wrinkle, and this is the condition which we guard against when the pipe is subjected to bending. This wrinkle forms across a large compressive strain, in these tests it was in the order of 0.7%.

Q Would you point to the wrinkle?

A That's it.

Q That ridge around the pipe?

A Yes.

MR MARSHALL: Dr. Price, perhaps you could hold the mike and speak directly into it so others in the audience can hear more clearly.

A Yes, this bulging here is a wrinkle. It starts on the compression side of the pipe and then progresses around it, as per bending curves. Here is a slide, a picture of the wrinkle that has formed all around the pipe, as you can see it is quite pronounced. I have got a closeup of that I will show next. The point to note here is that the deflection at which they stop pulling this pipe were in the order of 20 times those when the wrinkle first initiated. We base our design criteria to strains lower than those which occured when this occured here.

Here's a closeup of that wrinkle, with the gross wrinkle after it's formed all around the pipe.

THE COMMISSIONER:
Q You described that ridge around the pipe as the wrinkle What about the longitudinal change in the pipe? Is that what you call a buckle or --

A This is a longitudinal effect. It can be considered as a buckling longitudinal in the wall. It is a local crimping up caused by longitudinal stress. Longitudinal strain, rather, in-elastic plastic strain. That's all the slides I have.

Another point to note is that the formation of that large wrinkle the full pressure was still in the pipe, and that was in the order of 950 pounds, the pipe was still fully pressured in the order of 950 pounds.

Q You mean there would have been no escape of gas?

A Right.

Q As if it had been carrying gas.

A Right.

Now, the design, to prevent this occurring we limit what is known as the curvature. I put it together here to show you what a curvature is. Here I have got a section of pipe which is subjected to some sort of bending and I have taken a little element out of here, which I have enlarged here, as a result of the bending, a radius, a curved radius is imposed on the pipe. This is called the radius of curvature.

And the reciprocal if that is called the curvature, it is just a convenient term but divided by one, you get the radius out if the pipe is bent.

MR. MARSHALL: Dr. Price, do you think you could hold the mike up?

WITNESS PRICE:

A In the bending the pipe on the blue side of the curve a compressive strain is imposed. This varies linearly through to that side, where you have a tensile strain. And in this area here, a wrinkle will form at a certain curvical compressive strain.

Differential heave will impose bending on the pipe and change the curvature. As shown here, here is a length which is heaving up. That's what happens. The amount of movement which can occur is strongly dependent on the geometry over which heave occurs, and this is a simple configuration. It is dependent on the geometry, the size of the temperature differential which is applied to the pipe, dependent on the gas pressure, all these things influence the bending behaviour of the pipe, and for that reason, we limit the curvatures because that is a sensitive parameter in the pipeline, rather than absolute movements.

However, for design purposes we are working on techniques now to model the interaction with the pipe and with the frost bulb to predict these movements for design purposes.

The same thing occurs for

differential settlements. Once more the amount of settlement it can tolerate is dependent on the geometry, that is the length, the gas pressure, the temperature differential, and the overburden weight, the weight of the soil pushing it down.

In some areas where buoyancy is a problem, I believe the pipe will be normally weighted with concrete weights at a close spacing, and stop the flotation. However, some areas may be desirable to use anchors and for a case like that, it will be necessary to consider the buckling effect due to the actual load,the temperature differential and the gas pressure. The criteria is to limit the length between anchors so that doesn't occur.

A similar thing occurs at loss of support, we can predict a safe span for loss of support, although this will not be a normal construction procedure, it is purely for guidance as to what will be a safe span should this occur, and the objective of this span will be to prevent this overall in stability.

At changes of alignment, the pipe is bent in a bending machine to impose a residual curvature. After the pipeline is put into operation, the effects of these changes in alignment is to cause an unbalanced component to the actual force which is developed by the gas pressure and the temperature differential. This resists,I've shown it diagramatically here. This is resisted by the soil bearing pressures or by the weight of soil at overbends.

The effects of this force is to tend to push the pipe into the ground like that. The governing load condition here is a temperature differential, and the higher this becomes, the more drastic this force is. For north of the 60th parralel, however, the differential that we expect during the design which will be of a maximum order of 72 degrees Fahrenheit.

MR. MARSHALL: Could you hold the mike a little closer, Dr. Price?

WITNESS PRICE:

A It will not lead to any serious problems.

Here I have drawn some field bends. Here is an overbend configuration and I have shown it lifting off the ground as a result of an increase in temperature. The amount of this movement would depend on the temperature differential once more, and on the weight of the soil overlying it. The criterion here is to provide sufficient overlying soil to prevent excessive movement which could wrinkle the pipe in that area, or which could cause the pipe to push out of the ditch and buckle. This is the criterion for depth of burial which we feed to the-- which the geotechnical design would establish.

The areas of side bend, a similar effect occurs. It is a lateral movement pushing into the soil which is resisted by bearing pressure of the soil. It has a typical distribution. This movement once more depends on the magnitude of the temperature differential and on the type of soil that is supporting the pipe. for very weak siols this movement would be larger than it is for very strong till type soils.

The criterion here once more is to limit these movements so that you don't wrinkle the pipe, that you don't excessively fail the soils so that the pipe could fail in a buckling mode and push out of the ditch. A similar condition exists for sag bends, sag bends are a similar condition as side bends. It poses a bearing pressure on the soil on the bottom and moves downwards. That is all I've

got, sir.

THE COMMISSIONER: Could I ask you one question, Dr. Price?

Q You said that the tendency to wrinkle or buckle depended on a number of things, but let me just put it to you this way. You have the gas, the pressurized gas in the pipe. Then around the pipe you have the earth, it may be frozen, unfrozen, it may be weak, it may be strong. I think all of us as laymen understand that; but you said it depended as well on temperatures. Would you just explain to me what you meant by those temperatures?

A The buckling depends on temperatures.

Q Did I get you correct?

A Yes. What I am getting at there is the temperature differential that is a load condition which imposes a longitudinal strain on the pipe, and it is this strain together with -- added to that bending strain which causes that buckle to form.

Q But what do you mean by "temperature differential"? I'm sorry.

A Temperature differential is an increase in temperature of the pipe steel from a stress free situation when it is initially installed in the ditch, and restrained. When it is buried, gets restrained. Now if the steel temperature changes or increases, it will want to expand; but the soil is

holding it back and it cannot, so it imposes an equivalent strain or stress in the pipe to overcome that tendency to expand. This effects, at bends, for example, the bend wants to expand but cannot so it pushes in sideways into the soil.

THE COMMISSIONER:
I see, thank you.

MR MARSHALL: Mr. Commissioner, in addition to the materials that have been circulated, as being the substance of the evidence that is to be given by this panel, I wish to have them address the subject of above ground piping, which has been raised in the cross-examination of the previous panel, and Mr. Purcell will address this topic. The remarks that he will make later in the testimony, I've had reproduced and I have copies available for the other counsel. I'd ask Mr. Carter to pass them around.

THE COMMISSIONER: Yes, thank you.

MR. MARSHALL:

Q Sir , if we turn to the prepared testimony and the topic of station design. What were the responsibilities in the station design section?

WITNESS PURCELL: This section was responsible for the mechanical, electrical, and local control design of the compressor, chilling and cooling stations, and for preparing the cost estimates for permanent materials (other than civil structures) used in the station. As part of this responsibility, the section made estimates of noise levels

and emissions to be expected from the stations.

Q How were the stations designed?

A Wherever possible, the stations were designed using conventional practice. Station mechanical equipment, pressure vessels and control valves were located in buildings where practical, for protection against climatic conditions. Equipment, piping and pressure vessels which were located outdoors were designed to operate safely at the ambient temperatures which can be expected in the vicinity of the proposed pipeline route. Buried or protected piping in stations was designed to operate at temperatures down to minus 20 degrees Fahrenheit, which is below the minimum expected flowing gas temperature and below the coldest expected ground temperature at pipe depth. The stations were designed to operate by automatic control with remote set-point adjustments from the Gas Control Centre.

Q Would you describe the various stations that have been designed for this system north of the 60th Parallel?

A The stations on the pipeline system north of approximately Fort Simpson are designed to chill the gas to temperatures below the ground temperature in order to preserve the stability of the permafrost surrounding the pipeline. There are 15 proposed stations located in this portion of the system which are typically the same. The designs of the

stations in this group are based on using a single 30,000 horsepower (ISO) -- now that's a method of rating a turbine that measures its performance at sea level and 59 degrees Fahrenheit -- tubine driven centrifugal compressor package for main gas compression and a closed loop propane refrigeration system for gas chilling. The refrigeration system designs are based on using a single gas turbine of approximately 17,000 horsepower (ISO) for compressing propane. An exception is station M-03 which is located at the Travaillant Lake junction where a double chilling system using two 17,000 horsepower (ISO) turbines for compressing the propane is required. Each refrigeration system is designed to remove the amount of heat from the gas stream equivalent to the energy imparted to the gas by the gas compressor at the station, plus the heat flux from the ground to the flowing gas between that station and the next station upstream.

There are four proposed stations located in the transition zone between the chilled portion of the system and the air-cooled portion of the system, where the gas temperature can be allowed to arise to conventional levels. No chilling or cooling is necessary at these stations. The designs of the first two stations in the transition zone are based on using single 30,000 horsepower (ISO) turbine driven centrifugal gas compresssor packages for gas compression and are similar to those in the North with the exception that the chilling facilities have been omitted. The second two stations in this zone require more horsepower because of higher flowing gas temperatures. The designs of these two stations are based on using two 27,500 horsepower (ISO) turbine driven compressor packages at each station and are similar to those stations in the air-cooled section with the exception that the air-cooled heat exchangers have been omitted.

Q Mr. Commissioner, Mr. Koskimaki has a slide which shows the layout for a compressor station and he would like to present that and review the installations.

WITNESS KOSKIMAKI:

A This slide shows an artist's sketch of a 30,000 horsepower station with refrigeration. It's based on the preliminary layout which is shown on the application.

The pipeline is located underground on the upper left hand side of the station

site, approximately a hundred feet from the station fence right through here. The gas flow goes from left to right. The station block valves and the station bypass valves are located underneath these small buildings. Projecting above the ground are shown the pipeline scraper traps.

The gas enters the station at approximately 1385 psig and zero degrees Fahrenheit under normal operating conditions. It passes through this inlet block valve here, goes out of the ground and enters the inlet scrubber building. The inlet scrubbers are provided to remove any liquid or dirt which may be entrained in the gas stream for protection of the centrifugal compressor.

Leaving the scrubber building, the gas then enters the main compressor building where it is compressed to a pressure of between 60 and 80 and 60 and 90 psig. This compression causes the temperature to raise to approximately 24 degrees Fahrenheit.

After compression, the gas flows through this pipe here and enters the chilling building where it is refrigerated to a temperature of approximately 12 degrees Fahrenheit. After refrigeration, the gas then comes back in the ground and passes through this discharge block valve into the main line at a pressure of 1680 psig.

When the gas reaches the next station, approximately 50 miles away, it -- the expansion down the pipeline will cause the temperature to drop.

back to zero degrees.

THE COMMISSIONER:

Q That's due to loss of pressure?

A Yes, so the process can be repeated at the next station.

Q So it comes in at --

A At zero.

Q At zero, you increase the temperature --

A Yes, and chill it.

Q And you chill it?

A And it leaves at 12 approximately, and as it expands down the pipeline it returns to zero again.

MR. GIBBS: Mr. Commissioner, could you tell us the size of the area?

A This is 1200 feet this way by 900 feet in width.

The refrigeration system which we are using to chill the gas is a closed loop propane system which operates by observing heat from the gas stream to evaporate propane in the gas chillers, which as I said before are located in this building here.

The propane vapours then are compressed in this building to a high enough level so that cooling by ambient air temperature through the heat exchangers or condensers will cause it to condense. The condensed propane then enters this receiver -- you can;t see it very good there, but

there's a receiver there and from the receiver then the liquids flow back through the economizer to the chillers for re-evaporation.

The economizer is a pressure vessel which takes a portion of the propane. It allows a portion of the propane to vaporize at an intermediate pressure and returns it to the compressor at that interstage pressure to save on horsepower and fuel.

The central heating system hot water heaters and the electrical generators are located in this building. The motor control centre and the control room are in this building. These buildings are the operating and maintenance buildings. Equipment storage, garage, living quarters and water storage. These tanks are the diesel fuel storage tanks for operating and maintenance. These are 750 barrel storage tanks.

This tank here is -- receives liquid from the inlet scrubbers for storage, should any leakage happen to occur or be collected in the scrubbers.

Away from the buildings is shown the flow stock liquid incinerator, and the fuel gas heater. That's about it.

MR. MARSHALL: Thank you, Mr. Koskimaki. Could you describe the manner in which the station size was selected?

WITNESS PURCELL:

A The station sizes were selected as the result of an economic study considering those compressor units which were commercially available at the time of the study. Calculations were made to determine the number of stations using each type of unit which would be required to deliver an equal annual volume of gas at the end of each section. The lowest total cost of owning and operating the stations was the primary criterion in selecting the station sizes. This is discussed further in Section 8.b.1.2 of the Application.

Q What emissions will be produced by the stations?

A Calculations were made to predict ground level concentration of sulphur dioxide and nitrogen dioxide (converted from nitric oxide) around the stations using manufacturers' data for emissions of oxides of nitrogen and assuming the maximum levels of sulphur and hydrogen sulfide permitted by the pipeline gas specifications. This prediction was made using a wide range of wind velocities and ambient conditions for a radius of up to 100,000 feet around the stations.

The results showed that the concentrations of either sulphur dioxide or nitrogen dioxide would not exceed the ambient air quality standards of the Province of Alberta or the limits stated in the Federal Clean Air Act. To the best of my knowledge there are no more stringent standards which

pertain to the areas where stations could be located.

MR. MARSHALL: Mr. Commissioner, there is to be a further consideration of the question of emissions as part of the second phase. You have directed in the preliminary rulings that we deal with the impact on air and it was thought that we could deal with this subject in more detail then.

Q Can you comment on the noise that will be generated by the compressor stations?

A Calculations to predict noise levels from the 30,000 horsepower stations with refrigeration facilities and 55,000 horsepower stations with cooling facilities have been made. The calculations were based on using manufacturers' sound power level data from each noise source in the station. The results showed that when using conventional silencing the maximum noise levels at the station boundaries would be about 70dBA and the maximum levels 1,000 feet from the station boundaries would be about 50dBA. Additional noise data appear in Section 8.b.1.4.3. of the Application on page 17.

Q Could you give us a reference point, sir? Could you tell us what 70dBA means or 50 dBA? What would that be equivalent to?

A Mr. Koskimaki did these calculations. He could respond to that.

WITNESS KOSKIMAKI:

A 50dBA is more or less

classified as a quiet residential area. It's also the limit which Alberta specifies is the maximum within 10 feet of any occupied residence.

Q And what about 70dBA?

A 70dBA is a level that more or less you would expect in your living room while you were running the vacuum cleaner or the T.V. was on, a fairly loud level, or it would be the level that you would find 100 feet from a freeway, say something like 10 in the morning when it is being fairly well used.

MR. MARSHALL: Sir, again this is a subject that we propose to deal with further in phase 2.

Q Turning, sir, to corrosion. Would you please explain how the corrosion aspects of the project were studied?

WITNESS PURCELL:

A Northern Engineering retained expert consultants in the field of corrosion. They reported to our corrosion engineer who was responsible for liaison with the other sections of Northern Engineering, directed several testing programs, and performed the administrative functions of the section. We were also able to take advantage of the experience and knowledge of the members of the Corrosion Subcommittee established by the project's sponsors. This Subcommittee met on a regular basis to review our work and give advice on our programs. Our consultants and our corrosion

engineer attended and participated in these meetings.

Q What is the significance of corrosion to a pipeline?

A An effective corrosion control program on any pipeline system considers external, internal, and atmospheric corrosion. External corrosion control for a buried pipeline has historically been accomplished by using a suitable coating, combined with the successful application of cathodic protection.

It was therefore necessary to determine what coating types would be suitable for the constuction and operation characteristics of this pipeline and whether or not cathodic protection could be applied successfully. Other factors that needed to be considered were the electrical, chemical, and biological characteristics of the soils surrounding the pipeline and the susceptibility of the pipe to stress corrosion cracking.

An effective internal corrosion control program requires methods of controlling and monitoring the gas composition to keep internal corrosion to an acceptable level.

The probability of severe atmospheric corrosion on this project is low except possibly in the northern marine environment. However, to prevent any surface corrosion as well as for appearance purposes, all exposed metal surfaces will be painted.

Q Please describe the testing

programs and studies that were undertaken in these areas.

A A coating evaluation program to determine suitable coating was carried out. This coating evaluation was based on tests performed on various coatings at low temperatures as well as the past experience of our consultants, the Corrosion Sub-Committee and the industry as a whole.

Cathodic protection test installations were made at Sans Sault, Northwest Territories, and at Prudhoe Bay, Alaska. Laboratory and field tests were undertaken to determine soil resistivities, the effect of temperatures on resistivities, and the effect of anode backfill and temperatures on ground bed design. Laboratory tests were carried out on low temperature polarization and corrosion rates. A chemical analysis of soils was performed on soil samples obtained from representative areas along the pipeline route. A literature search on the activity of bacteria in northern climates was made. Tests were conducted to determine the susceptibility of the proposed pipe to stress corrosion cracking.

A study of the internal corrosion histories of operating pipelines was made to determine the effect of various impurity concentrations on the rate of pipe corrosion.

Q What are your conclusions regarding the designs of the project from a corrosion standpoint?

A The tests we have made

and the experience of the people involved in the corrosion studies indicate that conventional external coating systems will give reliable service in a permafrost environment and that a pipeline buried in permafrost can be cathodically protected.

It has been well established that at ambient temperatures or lower, and regardless of impurities in a gas, there will be no corrosion if there is no accumulation of liquid water or a liquid water solution. Internal corrosion in the line can therefore be controlled by limiting the amount of water in the gas to a level that will preclude condensation of liquid water and by providing facilities and procedures for removing any liquids that may temporarily accumulate.

Q Would you describe, sir, the communications system required to operate the pipeline?

A The pipeline requires a suitable facility such as a microwave radio syatem or satellite system which would carry the following sub-systems:

- private telephone network;
- data acquisition and supervisory control systems, including (a) gas control system; and (b) maintenance information system;
- mobile radio system;
- teleprinter system.

Preliminary designs of all

sub-systems were incorporated into the system design to determine its required capacity. These designs were based on projected voice communications traffic loads and data transfer requirements derived from information about the operating pipeline.

For the design that was the basis of the application, a conventional microwave system was selected. This selection was made very early in the project before satellite systems and digital microwave equipment became readily available as proven designs. Cable systems were rejected because of suspected problems with buried cable in permafrost, and because of the unsatisfactory reliability characteristics of buried cable which is often dug up and broken if not buried deep enough. We are carrying on further evaluations and may recommend the adoption of a satellite system.

Q Please describe the communications system required to construct the pipeline.

A If a microwave system is selected for the permanent communications system, the pipeline communications requirements during the construction period would be satisfied by early construction of the permanent facility, or by temporary microwave radio links to the construction camps. The degree to which the existing telephone networks would be extended to the construction camps over this microwave equipment would depend on whether the microwave system

is owned by the pipeline or leased from the Telephone Company. In the leased case, fewer communication repeater sites would be required than is shown in the application. A mobile radio system with a mobile radio console at each construction camp and stockpile site would also be required.

Should a satellite system be adopted for operating the pipeline, it would be implemented as soon as required to provide communications service for constructing the pipeline. In this case, communications sites are required only at the construction camps and stockpile sites. A mobile radio system and some public telephone services would supplement the satellite carried services.

MR. MARSHALL: Mr. Commissioner, Mr. McMullen has some slides and graphs that he would like to present dealing with the communications area.

THE COMMISSIONER: Just a moment, Mr. McMullen. This goes back to yesterday, Dr. Purcell, and I just thought I'd ask you before it slips my mind. You said yesterday at page 24 of the notes that you presented that Arctic Gas was investigating automatic welding as well as manual welding processes, and you said that Arctic Gas might, for purposes of carrying out the girth welding in the field, use automatic welding machinery but that no decision had yet been made by Arctic Gas. Now can you tell me if you know -- and if you don't know, I will understand -- can you tell

me when Arctic Gas is likely to have reached a decision as to whether it will use welders in the field to carry out the various welding procedures, or automatic welding machinery?

A It would follow studies that are under way now, and these studies are aimed at developing techniques to weld, using both manual processes and automatic equipment. It would depend upon the results of those studies, and Mr. Holmberg, do you know the timing on those, those tests?

WITNESS HOLMBERG: I think we'll have a good many of those results within the next six months or so.

THE COMMISSIONER: Well, what concerns me, Mr. Marshall, is that the decision will bearing on the number of men employed in the field, wage and employment opportunities on the project. How many welders would -- this is probably in the application somewhere because when the application was filed the assumption was you would be using welders and not automatic welding machinery -- but can you tell me offhand how many welders were expected when the application was filed to be employed on the project?

MR. MARSHALL: I don't know if the panel has that information, sir.

THE COMMISSIONER: They may not.

MR. MARSHALL: The construction panel certainly will in that they have the breakdown of the manpower estimates that have been made. I can

certainly obtain further instructions on that point and ensure that the construction panel deals in some detail with the manpower and the techniques, if you like.

THE COMMISSIONER: Well, I won't pursue it then, but would you find that out for the construction panel, would you find out these things: When is Arctic Gas likely to reach a decision as to whether it will in fact be employing welders on the pipeline, or instead, using automatic welding machinery? How many welders were intended to be employed when it filed its application? Were any of those welders or were any of those welding positions intended to be opened up to northerners, and finally, in Arctic Gas's northerner training program, have any northerners been undertaking training as welders? Was there any intention earlier of their undertaking training as welders? That -- I raise those matters just so that I don't let them slip by. So carry on, then.

WITNESS HOLMBERG:

A Just one comment. I think that one point that should be clarified, and that is even though they use automatic welding, there will still be a large amount of manual welding. The intent is not to replace all the welding with automatic welding, and in either event, why, my recollection is that the number of employees will pretty much even out because of the number of technicians or helpers and men of that calibre that will be used.

THE COMMISSIONER:

Q Yes. Well I think that we should know a little more about that, in fact I think we should know a lot more about it, and it is something, Mr. Marshall, that you should be prepared, through your witnesses, to explain at some length in the construction panel.

MR. MARSHALL: Yes sir, this is another of those areas that sort of falls between two groups, if you like. There's an input from design and there's an input from construction, and we'll certainly follow through with the construction panel and give you considerably more detail.

THE COMMISSIONER: I think this is our kind of stuff:

WITNESS MCMULLEN:

A Mr. Commissioner, I would just like to quickly review what is contained in Section 8.b.7. of the application. It was indicated that studies were underway to determine

an implementation method for the pipeline communications system, and this would serve both the construction and the operations of the pipeline.

A microwave system, such as depicted here, was described in the application primarrily to provide information on land use and costs. Our objective in setting out design criteria for such a system was to obtain reliable communications, adequate capacity and to make sure that the implementation schedule of the communications sytem was satisfactory in the context of the proposed pipeline construction schedules.

In addition to these general objectives, we had two other prime objectives which was to prevent the situation where the pipeline activities would cause the degradation of the telecommunication services in the north. And to cooperate with the regulatory authorities and telecommunication common carriers in the north, to serve the public interest wherever possible.

Now, in these studies we were looking at integrated communication systems to both serve the construction and operation of the pipeline, and we narrowed the implementation methods down to three: The leased satellite system; the leased terrestrial microwave system; and the company owned and operated microwave system.

Now, I would like to digress a bit to cover the area of capacity in telecommunication systems. On this slide we have one voice channel,

many voice channels and a medium for carrying them.

Now, a voice channel when it's converted into a micromagnetic signal generally occupies a band width between 30 hertz, and 3.1 kilohertz. Now, this is a standard telephone channel. It's not the same spectrum that everyone talking -- for instance, a man's voice would contain more energy towards the lower end and a woman's voice towards the higher end, but the equipment that is provided for telephone use generally has the standard telephone channel.

Now, in long distance systems, it would be very uneconomical and inefficient to have, say one wire for every voice channel or one radio channel, so we multiplexed the voice channels together into a complex signal. In this case, we show a spectrum of 12 voice channels. This is known as a group of voice channels which occupies the spectrum between 60 kilohertz and 108 kilohertz.

Now, it's possible to multiplex many, many more voice channels, in fact up to 1,200 in such a manner. Now these multiplex voice channels are modulated onto a carrier frequency in the case of a microwave system, which is shown here in the centre. This modulated carrier frequency occupies a band width of 3 megahertz, and this represents a voice channel capacity of approximately 300 voice channels.

Now, the band width that the signal can occupy, the modulated signal can occupy, is specified by the Department of Communications, and

the capacity is a result of that specified band with, plus the characteristics of the microwave equipment. This 300 channels, by the way, is typical of the microwave networks that are operated by C.N. Telecommunications presently in the north.

This is a schematic, it shows some of the equipment relationships that we're dealing with. This multiplex equipment here has many voice channels coming into it, and it has a complex signal contaning the information of many voice channels on one wire going to the microwave radio equipment.

The microwave radio equipment modulates this complex signal onto the RF carrier and it's transmitted up the transmission line to a directional antenna, which is mounted high on a tower. Now, the height of the antenna must be such that line of sight between this antenna and the next antenna is achieved.

Now, the distance that the two antennas are apart depends on the topography of the land, and in typical cases it's 20 to 30 miles apart. However, the compressor stations on the pipeline are on the average 47 miles apart, so between compressor stations we must have a repeater station somewhere.

On the lower part of the view graph we're dealing with the satellite system. The term earth segment alludes to all of the earth stations. The term space segment alludes to all of satellites that are being used in the satellite system.

Another term is transponder. A transponder is equivalent to an RF channel in very simple terms, but in this case the transponder has a band width of 40 megahertz which would carry one network quality television signal.

The satellite system that we are looking at is the one from Telsat Canada, it has 12 transponders in a satellite.

To turn to something more applicable to the pipeline system. This is -- shows our estimate of the number of voice channels required for the pipeline system during operation. Typically 66 coming up from the south to Fort Simpson; typically 54 from Fort Simpson to Norman Wells, and typically 42 between Norman Wells and Inuvik and typically 30 between Inuvik and Prudhoe Bay.

Now, this is -- these channels are estimated from the number of people that would be required to operate the pipeline, the type of work they would be doing, the location of their work, and also on the amount of data that is required to be collected from the compressor and meter stations, and taken to the district offices, and also back to the gas control centre in Calgary.

Now, to put this in some context, I would like to show the telecommunications network relevant to the pipeline, that C.N.T. or Canadian National Telecommunications will have in operation in 1976. Notice that along the Mackenzie Valley, there will be a microwave system capable of carrying

300 voice channels, but that's somewhat misleading, because for instance between Fort Simpson and Norman Wells, there also must be circuits assigned from Hay River to Inuvik, so the capacity available in this section here depends on really the circuit assignment of the multiplex scheme, and it would be somewhat less than 300.

We had provided the suppliers of communications with the functional specifications, and one of the proposals that we received was from a consortium of Telephone Companies, and they have proposed to build a new microwave system along the entire length of the pipeline, that is duplicating the facilities that even now are being constructed for 1976. The capacity of these facilities will be certainly greater than is required for the pipeline, and there is potential for other telecommunication users in the north to use this excess capacity, should it be built.

Now one of the other proposals that we received was from Telsat Canada, who is a satellite company, a domestic satellite company in Canada,and this depicts the satellite system serving the pipeline, and notice there are many, many air stations built along the pipeline. Now these are stations that would also have some excess capacity so there is a parallel between that and the microwave system proposed by the Telephone Companies.

I now have some slides that we -- Telsat Canada has been kind enough to loan us, and I would like to present them by way of further information.

THE COMMISSIONER: At the moment, Dr. McMullen, you say that Arctic Gas intends to use a conventional microwave system. Is that a firm decision or is that a matter that's under review in the light of these proposals that have been

advanced by Telsat Canada and the consortium of Telephone Companies?

A At tht time that the application was made we recognized that we were looking at various implementation methods, and that the decision had not be made, and that decision still has not been made. So that we are in the process of going through it now.

Canada has two telecommunication satellites presently in space. Anik I is parked in a geostationary orbit over the equator at 114 degrees longitude, approximately straight south of Yellowknife. Anik II is 109 degrees longitude, that's approximately straight south of Fort Reliance at the other end of the lake. Next month, Anik III will be launched and it will be parked at 104 degrees longitude, and that's -- that will be the full complement of satellites that Canada will have up until these ones wear out, of course. Anik I, which is the one shown here, has nine of its transponders presently assigned. There are two others which are held in reserve for backup in case one of the other transponders fail, and there is one spare channel which Telsat Canada have proposed for the pipeline's use.

Now, the pipeline will actually use about half of the one broad band channel on Anik I, half of its capacity, so we are taking up about 1/20th of one of these satellites by way of using existing resources. The next one.

This is a schematic again of how the pipeline will be served. One of the channels in Anik I will be used for operating the pipeline in the primary mode, and it's shown going to the larger of the two antennas on the first station here.

On Anik II we will have a control channel which will monitor the health of Anik I, so that should Anik I have a catastrophic failure, that is the whole satellite go some way, it's possible to switch over to Anik II, and we can see that in the next slide.

Anik II is now serving the pipeline, and when Anik II, if it should fail, pardon me, we would first set up Anik II as the primary satellite and the control would be moved to Anik III until such time as Anik I was replaced again.

Here we see what the effects of losing one earth station is on the system. Notice that it would not affect any of the other stations if it fails. Now I might mention that should the communications length be severed to any compressor station, it will operate, it will continue to operate in a safe, secure mode at the last set of instructions received from the gas control office.

This is a portable air station which might possibly be used during the construction of the pipeline, it provides a very flexible system.

This is the approximate size of one of the earth stations at a District Office. There

would be, however, two antennas approximately the same size. These would be located at Inuvik, Norman Wells, and Fort Simpson, right next to the existing remote television receiving air stations.

This last slide shows the coverage possible from this satellite. In the Telsat proposal they have proposed to service the pipeline, the complete pipeline from the 49th Parallel here and also including Alaska. That's the end of my slide show.

THE COMMISSIONER: Thank you very much.

MR. MARSHALL: Q Mr. Purcell, from your standpoint, what special considerations are associated with (a) the East of Fort Simpson route revision, and (b) the 42-inch supply line alternative?

WITNESS PURCELL: For the most part, our work on these modifications was conventional. IN each case we received route information from responsible people and determined where the compressor station should be located for optimum hydraulic performance. These locations were reviewed by others for conformance to their criteria concerning suitability from the terrain and other environmental points of view, and adjustments in the locations were made where necessary. In the case of a 42-inch supply line alternative, we determined which compressor stations would be required to be constructed earlier. The need for earlier station construction to transport the same gas volumes as a result of the larger pressure

drop in the 42-inch pipe, compared to the 48-inch pipe used in the original application.

Q In your area of responsibility are you satisfied that the pipeline design is technically feasible?

A Yes. The engineering designs in each of these areas have been performed according to good engineering practice, using existing and tested technology and within the project's constraints, the major system parameters have been selected to give minimum unit costs of transporting the gas. The pipeline design therefore in my opinion, obeys the rules for good engineering design and is technically feasible. I will deal in turn with each of the design areas for which the panel was responsible, and explain the reasons why we believe the design is feasible.

1. Systems design. Four basic steps were taken in the system design area to assure that our overall system calculations were valid and gave correct results. The first of these was to base all our system calculations on the fundamental physical laws. The second was to use proven and well tested equations wherever possible, provided we could also derive them from the fundamental laws. Thirdly, we used experimental data to check our techniques in new areas where this was necessary. And finally, we spent considerable time in carefully selecting realistic, practical data for use in our techniques.

2. Pipeline design. The mechanical design of the

pipeline, scraper traps, valve settings and measurement stations uses designs that have proven to be reliable in the gas transmission industry. The components for these facilities are based upon sound material specifications. We have a considerable amount of evidence from manufacturers, based on their experience and tests, that the essential requirements of these specifications can be met.

3. Metallurgy.

The majority of the developmental work on the materials specifications was performed by the Metallurgical Subcommittee which is composed of the principal metallurgists of several of the project's sponsors. Mr. Holmberg, representatives from Battelle Memorial Institute and Canadian Arctic Gas and Northern Engineering's metallurgists attended and contributed to the deliberations of this group. The Subcommittee members brought to the project a wealth of experience and knowledge and have been working intensively on the project since the fall of 1969. Their work has included numerous meetings with technical experts from companies manufacturing pipe and other components of the system. The purpose of the meetings was to compare the project's requirements with the manufacturers' capability so that material specifications could be developed that could be met by the manufacturers and would result in materials that were appropriate for the requirements of the project.

In discussions with the manufacturers, the Subcommittee indicated the need for evidence that the specifications could be met, especially with regard to requirements that were more stringent than in other specifications. In many cases, the manufacturers rolled pipe and fabricated pipeline components to our specifications, so that tests could be made to verify that the specifications requirements had been met.

Because of the degree of expertise brought to bear on the metallurgical aspects of the project, the thoroughness of the work, and the confirming evidence from manufacturers, we are confident that the metallurgical designs meet the requirements of good engineerng practice.

4. Stress Analysis.

We are satsified that the pipeline structural design is technically valid and that the pipeline would remain serviceable under probable applied and potential loadings. In establishing design criteria, we relied on the past experience and efficient operation of existing pipelines for the usual conditions encountered in pipeline design. For the special conditions applicable to this project including stability at field bends and frost heave, we developed modifications to a recognized computer program to analyze stresses and deformations in buried line and the interaction between buried pipe and frozen and unfrozen soils using modern analytical methods. Results of analyses using this computer program assisted the geotechnical study groups in establishing geotechnical criteria designed to assure the integrity of the pipeline. For earthquake loadings and seismic design criteria, we relied on the recommendations of Dr. N.M. Newmark, who is well known for his expertise in seismic resistant design.

All structures, including schools, churches, high rises, et cetera are vulnerable to

extreme contingency type loading and so would be the pipeline. The stress analysis does not consider this type of loading condition, which includes massive landslides, washouts, et cetera. The design approach is to locate the pipeline so as to avoid such areas.

5. Station design.

The design of the compressor stations wherever possible incorporates well proven concepts. The chilling stations are based on concepts proven reliable in the gas processing industry. The components used in the high-pressure gas piping in the stations are based upon the same material specifications and supported by the same evidence discussed under Pipeline Design.

6. Corrosion.

Pipe coating materials and cathodic protection systems have been determined to be effective in a permafrost environment. The remainder of the corrosion concerns differ little from those for a conventional pipeline and corrosion can be controlled by well proven procedures.

7. Communications.

The communications system design underlying the application is a conventional, well-proven design. We have considered and satisfied in the design the need for unusually high unit reliabilities due to the length and complexity of the pipeline system. Other types of communications systems are available to us and may provide even

more reliable service. This is one of the most important factors that will be considered when a communications system is selected for final design.

Q Mr. Purcell, I would like you to deal with the question of above ground pipe, the materials that I circulated a few moments ago.

Has consideration been given to placing the pipeline above ground?

A It has been suggested from time to time and because of the discussions that have taken place in these hearings earlier, I thought it was a good idea to put down all our thoughts, so what I am going to read reflects the feeling of this group of people, and it has been reviewed by Dr. Clark on the geotechnical group and he is in accord with what it says.

The traditional method of installing cross-country gas-transmission pipelines in North America is buried construction, regardless of the terrain crossed. Above-ground construction is used rarely and then only in special circumstances, such as at crossings of rivers with unstable and unpredictable channel action. The original concept for the Arctic Gas Pipeline included the traditional buried construction method, with gas chilling in permafrost regions to avoid melting the permafrost.

The reasons for intially selecting the buried construction mode included:

1. Pipeline companies are

familiar with and have confidence in the buried mode.

This was back in 1969 when we started on this project, and I think point number 1 simply relates to the fact that you start on something new at the point which you're most familiar with it.

2. A buried pipeline is much less vulnerable to damage by man. An above-ground pipeline could be subject to damage during right-of-way maintenance activities, by other construction activities, and by deliberate acts by man.

3. An above-ground pipeline would present a barrier to migrating animals.

4. An above-ground pipeline is aesthetically undesirable.

5. An above-ground pipeline would have to be insulated so that hydrocarbon liquids would not form in the gas at low ambient temperatures. Alternatively, the gas transported would have to be primarily methane (the lightest hydrocarbon component of natural gas), which would seriously reduce the energy-carrying capacity of the pipeline and would present the gas-processing plants with the problem of disposing of the heavier hydrocarbon components.

6. Once the pipeline is insulated, chilling stations would be required to prevent the flowing gas temperatures from increasing to unacceptably high levels as it is compressed at successive compressor stations. As a result, there would be no difference in the station compression and chilling facilities between a buried and above-ground pipeline.

7. A special metallurgical design might be required for an above-ground pipeline. During a pipeline shutdown or before going into operation, the pipe temperature would gradually approach the ambient temperature. For a buried pipe that has been shut down, the pipe temperature will be the same as the ground temperature, which in the wintertime is much warmer than the air temperature. The low temperatures to which an above-ground pipeline would be exposed could require steel properties which might be unattainable in large-volume production or might be prohibitively expensive.

8. An above-ground pipeline would require larger concentrations of methanol in the test fluid, because the test fluid would reach a lower temperature than in a buried pipeline.

9. An earthquake resistant design would be more difficult for an above-ground pipeline, especially if it had to be elevated at intervals to provide passages for animals.

Some information from Russia was available at the time the initial studies for the Arctic Gas pipeline commenced, which indicated that the Russians were planning to construct their gas pipelines in permafrost on pile supports, rather than use the buried construction mode. Because the information related only to planning -- this was again back in 1969 -- rather than reflecting experience, it did not weigh heavily at these early stages.

Attempts have been made to gain information from the Russians as to their experience with construction of gas pipelines in Siberia. Although exchange visits have been held, limited information has been obtained, certainly there has been insufficient reliable information upon which we could base our design. Mr. Fielder of Arctic Gas, who has been involved in these exchange visits, will be giving evidence as part of the Construction Panel.

After reviewing the pros and cons of above-ground versus buried construction, the Arctic Gas engineers continued to use the buried mode as their prime design technique, and put the above-ground mode on the shelf to be used only in the event insuperable problems with the buried mode emerged. Geotechnical studies and design were concentrated on overcoming the problems encounterd with the buried mode, such as frost heave, slope movements, and the maintenance of drainage. The geotechnical people now state they are confident they have solutions for these problems.

A study was done recently to compare the costs of above-ground versus buried construction for portions of the route from Wrigley to the 60th Parallel.

This was more precisely from Milepost 500, which is about the Black Water river crossing on the pipeline route to the 60th Parallel. This section was identified and its characteristics were developed by Dr. Clark's people.

In this 300 mile long section where the pipeline is proposed to operate in the chilled mode, about 200 miles of the terrain is unfrozen. The unfrozen terrain appears in about 30 percent of the route in the northern most spread in this section -- that's the construction spread -- and increases at the southern end to a level such that an above-ground pipeline would not be buried as it crosses the very short frozen areas. The study was based on burying the pipe in the frozen sections and installing it on pile supports in the unfrozen sections.

A very preliminary design for the above-ground sections was prepared in order to be able to produce cost estimates. The pipe was assumed to be supported at 100 foot intervals on 35 foot long 20 inch diameter supports.

I'm afraid, Mr. Marshall, we've left out a line here. I think this said that anchors were assumed to be installed at about 2,000 foot intervals, and the pipe to be insulated and placed in a zig- zag configuration to provide the needed flexibility for temperature changes. Timber cribbing between pile supports would be used to accommodate the increased load during hydrostatic testing, and then removed. No special metallurgical designs were used, as the extensive studies and tests required to produce these designs have not been done.

The cost estimates showed that installing 200 miles of pipe above ground in the 300-mile section would increase the costs by the following amounts. The costs are shown in 1974 dollars, and do not include indirect costs. About 50% would have to be added to account for cost escalation and indirect costs.

Indirect costs include interest charges and so forth.

Now there is a tabulation of categories of cost, they are expressed in millions of dollars of extra cost for the above-ground installation.

Pile supports $188 million dollars.

Insulation $ 53 million dollars

Savings in ditching,
backfill, cleanup & berms -- that's a savings or a credit to the above-ground installation of 31 million

Cost of special metallurgical designs is not included. The total extra cost is $210 million. This extra cost can be compared to the estimated cost of constructing this 300-mile section in the buried mode of $339 million. So it's an increase of about 60%.

I said earlier that an above-ground pipeline is more vulnerable to deliberate or accidental damage than is a buried pipeline. If the above-ground pipe were damaged severely enough to initiate a fracture, we believe that the pipe might fail over an extremely long length, because of the enormous energy released from the pipe during a failure and the fact that it could very well prove impossible

to design supports that would restrain the pipe, as the ground does for a buried pipe. An above-ground pipe that has failed would behave very much like an unrestrained fire hose under pressure, whipping back and forth. This whipping action could cause successive buckling so that the failure would proceed indefinitely along the pipeline. The ground prevents this type of behaviour for a buried pipeline that has failed.

If a failure in an above-ground pipeline did occur, it could be of sufficient length that repairs could take weeks or months. This interruption of revenue would be intolerable to the pipeline company. If an above-ground pipeline had to be constructed, and this restraint problem could not be overcome, the only prudent design might be to install a second or insurance line, similar to what is proposed for the major river crossings. The cost penalty discussed previously would then more than double.

At the present, we have concluded that short sections of above-ground pipe are feasible, if their use is indicated at steep banked, narrow watercourse crossings, for example. Pipe similar to that proposed for compressor stations could be used, which is available in relatively small quantities. Short sections of a few hundred feet could be replaced in a day or two if they failed.

We have determined that solutions are available to frost heave and other geotechnical problems. There is then no reason to install

long lengths of above-ground pipe, with their associated cost penalty and their environmental and aesthetic draw-backs. A buried pipeline provides the best solution.

Q Mr. Purcell, are there any concerns pertaining to facilities design capacity that were raised by the Board of the Government Assessment Group, that the panel wishes to respond to?

A We're not, I don't believe, prepared to respond to it right now,Mr. Marshall. We have the information with us and we could become prepared.

Q What reports and studies does the panel rely on in support of its testimony?

A I believe there's a list attached to the direct testimony that you distributed. We rely on that list.

MR. MARSHALL: Thank you, sir. That concludes the direct presentation of this panel's evidence.

You may wish to take the coffee break before we get on with the cross-examination.

THE COMMISSIONER: Perhaps we might. I think Miss Hutchison will let us know if that's feasible, as they say.

CROSS-EXAMINATION BY MR. GIBBS:

Q Dr. Purcell, does your design work include the Alaska and most northern border group sections, as well as the Canadian sections?

A We're responsible for the design work of Alaskan Arctic Gas. We are not responsible for the northern border work, or any other connecting facility south of the 49th Parallel.

Q Mr. Dau when he was giving his evidence on location, gave a general reference principle for pipeline location to the effect that all other things being equal, the most economical location is the shortest distance between the point of supply and the point of delivery. I am going to ask you if we can't develop some similar general principles for design, and I'd ask you to start by turning to page 5 of your prepared evidence and direct your attention to the last sentence on page 5,

> "The third objective was that the pipeline system should be an optimum design so that it could be built and operated to transport gas at a minimum unit cost."

Do you see that?

A Yes sir.

Q And Dr. Purcell, would you care to agree with me that we could adopt that to a general principle for design to this effect, that you are expected to design the optimum pipeline system to be built and operated in a given location, that being given by the location group, for the transportation of given volumes of gas, of given composition, at a minimum unit cost. Would that generally describe what your group is required to do?

A I think so, yes sir. It's Mr. Purcell, by the way.

Q You and I are both in that lesser academic category. I presume then since this panel is concerned with minimum unit cost of transportation, they can also talk about capital costs and rates, tolls and tariffs.

MR. MARSHALL:

We had expected that such matters would be dealt with at considerable length by yourself and others before the National Energy Board, and this panel is not prepared to get into those subjects, Mr. Gibbs.

MR. GIBBS:

Well, the answer is that this panel will not give those answers. Who gave you the location for the design purposes, Mr. Purcell?

A The specific locations were provided generally by Mr. Williams and the people working with him.

Q And when were you given the locations which enabled you to develop the design that went into Exhibit 54?

A Is that the original application?

Q Yes.

A I believe the route was settled on in the middle of 1973.

Q On page 4 of your prepared evidence, you say that-- right at the last paragraph:

"Our general instructions from the project sponsors, which were developed in part on the basis of the studies we performed, included the points of gas supply and delivery."

Were those developed by your group or by your sponsors?

A The points of gas supply and delivery were developed by the sponsors.

Q And when were you given those points?

A I don't think they've changed since 1972, the two supply points and the two delivery points.

Q All right. You also say, your instructions developed in part on the basis of your studies, included the gas composition. Who gave you that, or did you develop the composition yourself?

A This is one of the examples where our studies influenced the information that was, relating to the information that was given to us. We were given from the Prudhoe Bay producers several alternative compositions, and we did studies to determine which composition would give the maximum amount of B.T.U. throughput in the pipeline.

Q Those several alternative compositions were alternatives which a plant yet to be constructed could deliver to the pipeline.

A That's correct, by operating at slightly different temperatures.

Q And your influence was

felt, did you say, in the B.T.U. content?

A We did studies to determine which gas composition in a given system would result in delivering the maximum number of B.T.U.s throughout the pipeline.

Q And that has something to do with the number of -- the amount of liquids included in the gas.

A They are not liquids at the pipeline conditions.

Q No, but they're liquids at atmospheric pressure?

A That's correct.

Q And the third thing you mentioned in that paragraph is the design gas volumes for each operating year. Does that mean the average day throughput in each operating year?

A Yes sir.

Q But you have to build into your design sufficient capacity, I presume, for peak day volumes also.

A That's correct.

Q Who provided the gas design volumes for each operating year?

A They came from Mr. Horte.

Q And when were those provided?

A I'm not sure, Mr. Gibbs. I think they would have been in early 1973.

Q Can you tell me what the max day volume is, for the fifth year, for example?

A The maximum capacity of the pipeline?

Q Yes.

A They're shown in the application.

Q in Exhibit 54?

A Yes, sir. I'm not -- well I think Exhibit 54 is one volume, isn't it? The flow diagrams are shown along with the design drawings, I believe. The large sheets.

Q All right. Now, Mr. Purcell, does the group with you there on the witness stand represent the entire design group?

A They represent -- are there other people in the group, do you mean?

Q Yes, was --

A Yes there are.

Q -- for example was there a representative or representatives of Canadian Arctic Gas as part of the design group?

A No.

Q Were there representatives of the sponsor companies of Canadian Arctic Gas as part of the design group?

A I think as I define design group, it is that group within Northern Engineering, and its consultants that is supporting the parts of the application that are listed here.

Q Now sir, other than those items which we've touched upon, that is route supply, delivery point, gas composition and volumes by years, were the design group given any other input assumptions to work on?

A The decision as to the pipe size was not made by ourselves, it was made by Canadian Arctic Gas.

Q Who specifically told you what the pipe size was to be?

A They would have come to me probably from Mr. Walker or Mr. Harvey, whoever was in charge of engineering at Canadian Arctic Gas.

Q Both senior officers of Canadian Arctic Gas?

A Yes.

Q I suppose, Mr. Purcell, that with reference to the work that your group does, there's a point in time when the design is sufficiently firm that you can submit it to your client for final approval and then go into the printing process?

A Yes.

Q And when was that point reached?

A You're speaking now about the application material?

Q Yes.

A Mr. Gibbs, it went over quite a period of time, the discussion on the

material that appears in the application.

It would have commenced in 1973, and would not have been completed until shortly before the applications were filed.

Q Shortly before March of 1974?

A Yes, sir.

Q Did you refer the whole package at one time for approval, or would it have been approved over the years bit by bit as some part was finalized for design?

A It was reviewed section by section.

Q Prior to the printing process that resulted in Exhibit 54, were there any changes made in your design by the client, or did he accept each time your recommendations?

A I could be wrong, but I think our designs were pretty much accepted, and what most of the discussion centred about was the way to express them in the application, the words that went into the application.

Q So then, Mr. Purcell, you were satisfied by March of 1974 that what appeared in the application met the tests that you and I agreed would -- or the principle would apply to design, that you had designed the optimum pipeline system to be built and operated in the location given to you by Mr. Dau, to transport the volumes of gas given to you by Mr. Horte of a composition

which you worked out with the producers at a minimum unit cost?

A There were other considerations that kept us in some cases away from the minimum unit costs that are discussed in the application. The one that comes to mind, of course, is the 48 inch supply lines, where excess capacity was provided at a cost penalty, so that looping could be deferred inthe event the gas volumes increased above the design levels.

MR. GIBBS: Mr. Commissioner, I'm going to start referring now to a map, so it might be a convenient time.

THE COMMISSIONER: Well, we're still in difficulty, but let's adjourn anyway for a --

MR. GIBBS: I could continue, if you prefer.

THE COMMISSIONER: Oh, the coffee is ready, well all right.

(PROCEEDINGS ADJOURNED)

(PROCEEDINGS RESUMED PURSUANT TO ADJOURNMENT)

MR. GIBBS: Q Could Mr. Purcell be provided, please, with a copy of Exhibit 54? Location, design and capacity of facility section 8, and connecting pipeline facilities, section 9.

WITNESS PURCELL: I have one, sir.

Q Would you first of all turn to the map under tab 8-A, item 2, system map?

A Yes sir. The first map?

Q Yes, it's entitled:

"Continental Delivery System, Arctic Gas Pipeline System."

A Yes sir.

Q It's the only -- it's the first map under that tab. Do you have that?

A I do.

Q I'm going to quote some numbers to you, Mr. Purcell, just to give you a little comfort they're numbers taken out of exactly the same volume. They are taken from tab 1 under Section 8-B, table 1, projected average gas, average day gas volumes.

A Yes sir, I see that.

Q I have taken the liberty of rounding them a little bit when I give them to you, I haven't always included the decimals. Now, sir, having in mind your principle of designing a system to provide transport gas at minimum unit cost, starting

at the northend you've already, I think, told me that the two 48-inch lines coming together at Travaillant Lake do not accomplish that principle of transporting at minimum unit cost.

A Yes sir, that's stated in the application.

Q They don't meet that principle.

A Correct.

Q Then from Travaillant Lake down to Caroline, you have a fifth year volume average day volume of 4.488 billion cubic feet per day. I am leaving out the fuel.

A That's correct.

Q And you're going to carry that through a 48-inch .72 wall thickness pipeline.

A Yes sir.

Q And will that meet the standard of providing minimum transportation costs for that section of the pipeline?

A I believe it does.

Q And if you were going to provide minimum unit cost of transportation for the two northern supply legs, what size of pipeline would you install there?

A The 42-inch pipe size that is in the alternative application is a -- provides lower unit cost of transporting gas.

Q Now at Caroline, sir, which I think is referred to as the Caroline bifurcation point, at Caroline what you have in gas volumes is what -- are the volumes that came in at Travaillant Lake, less the fuel consumed in the transportation process.

A That is correct.

Q And that in the fifth year is 4.264 billion cubic feet per day.

A Yes sir.

Q And at Caroline, sir, that volume of 4.264 billion cubic feet per day is split into two equal portions.

MR. MARSHALL: Mr. Commissioner, I think with respect, that my learned friend is getting into an area that really pertains to the concern of the National Energy Board, inasmuch as he's dealing with matters outside of the Territories and in the Province of Alberta.

MR. GIBBS: Well, sir here this panel, Mr. Purcell has told me that they designed the entire system from Prudhoe Bay to the 49th Parallel, and that he did it to provide transportation of gas at minimum unit cost. I think I'm entitled to follow him down that system and determine how much of it was designed on that basis and how much of the design was imposed by his client.

THE COMMISSIONER: Well, at the moment I'm not prepared to stop you, Mr. Gibbs. But that doesn't mean, Mr. Marshall, that you shouldn't

raise the objection again if you wish to. I don't think we've really given Mr. Gibbs a chance to lay the groundwork for whatever he's coming to, and it seems to me it would stand to reason that we can't confine him to the area north of the 60th Parallel at all times. The considerations that he's concerned with as they affect the north, depend to some extent on what occurs south of the 60th Parallel. So carry on at any rate for the time being, Mr. Gibbs.

MR. GIBBS: Thank you, sir.

Q Now that even split at the Caroline bifurcation point, Mr. Purcell, was given to you by the client, was it not?

A Yes sir.

Q And that even split is intended to be carried south in one leg and south-east in the other in a 42-inch outside diameter pipeline.

A That's correct.

Q And did you design that 42-inch outside diameter pipeline, or was it given to you by the client?

A The size of it was dictated by the client.

Q Then, sir, going in the southerly direction, from Caroline, where the 42-inch pipeline reaches the Alberta-British Columbia border at Coleman, of the volumes then carried, one billion cubic feet are taken out and into the Alberta Natural Gas system, is it not?

A Yes sir.

Q But the 42 inch pipeline continues across southeastern British Columbia, the 49th Parallel, carrying now only 1.126 billion cubic feet a day in the fifth year?

A That's correct.

Q And did you design that portion of 42 inch line from Coleman to Kingsgate, or were you told to use that size by your client?

A That pipe size was given to us by Canadian Arctic Gas.

Q Given -- if you were given the task of designing that size pipe to carry 1.126 billion cubic feet per day for that distance from Coleman to Kingsgate, at minimum unit cost, I take it you would not have used 42 inch pipeline?

MR. MARSHALL: Well, Mr. Commissioner, I think I must object to this line of questioning once again. Mr. Gibbs will clearly have an opportunity to pursue the area at a later date at the National Energy Board, to deal with the instructions that were given by Arctic Gas with respect to sizing, the various delivery lines and so on.

Now, I appreciate your concern that he be allowed to lay the groundwork for questions, Mr. Commissioner, but it's my respectful submission that he's really getting into an area that does not pertain to the subject matters that are before this inquiry within the terms of the Order-in-Council.

MR. GIBBS: Well, sir, the --

THE COMMISSIONER: Excuse me,

Mr. Gibbs. May I ask you a question? Earlier in this hearing, you raised the likelihood of looping of the trunk pipeline in the Northwest Territories.

MR. GIBBS:
Yes sir.

THE COMMISSIONER:
Now, if these questions are designed to get at the likelihood of looping north of the 60th Parallel, that would have a bearing on the impact north of 60, and I'd be prepared to let you continue.

I only mention that because I must say as you have proceeded, I thought you were getting at that. If you're getting at something else, perhaps you might tell us now and we can consider that.

MR. GIBBS: My friend has brought this prestigious group of witnesses here to talk about design and capacity, and in their own prepared evidence, they say we designed the pipeline -- I can read it to you just to refresh your mind, sir. This is Mr. Purcell in his direct evidence. He says,

"I established three major objectives for the design group".

And the third one is this:

"The third objective was that the pipeline system should be an optimum design so that it could be built and operated to transport gas at the minimum unit cost",

and that system, of course, goes all the way from Prudhoe Bay to the 49th Parallel as he has said.

And I want to show sir, that the

amount of that system that was designed by this panel was restricted and was minimal, in fact restricted to the amount of Travaillant Lake to Caroline, and all the rest of it, sizing, was imposed by the plant and not by this group, and if we get to that point, then and my friend Mr. Marshall wants to produce his client to explain why that system was imposed on this design group, then I'm prepared to talk about it with him.

But in the meantime, I think I am entitled, subject to your ruling, to establish that this group didn't design the capacity of this pipeline at all.

MR. MARSHALL: I think sir, what Mr. Gibbs is doing with his last question as I recollect it, was dealing with the portion from Caroline beyond to Kingsgate and asking the witness what he would have proposed himself with an objective of optimization of the design. I think that's a very different thing from what Mr. Gibbs has indicated is his intent.

MR. GIBBS: Oh no, sir. He's told me that the top two lines are 48 inch because he was told to make them 48 inch.

THE COMMISSIONER: They don't meet his criteria.

MR. GIBBS: His criteria would be 42, he's told me that. Now I've got him down to the point from Caroline to Kingsgate and he's told me that the 42 is what he was told to do, and I want to

ask him what he thinks the appropriate size would be to meet his criteria of minimum transportation, and I propose to go over on the other side down to Mouncie and do the same thing, if I'm permitted to continue.

MR. MARSHALL: Sir again it's my respectful submission that that line of questioning ought not to be pursued. The concern that this inquiry relates to, the impact of the pipeline within the Territories and the question of optimization of design south of the 60th parallel, in my submission, ought not to be dealt with by Mr. Gibbs and the panel.

THE COMMISSIONER: Carry on, Mr. Gibbs.

MR. GIBBS:

Q Mr. Purcell, what size line would you have installed between Coleman and Kingsgate to carry the 1.126 billion cubic feet per day?

WITNESS PURCELL:

A For the gas volumes shown in the application, I suspect that a 36 inch pipeline would provide lower transportation cost than the 42 inch.

Q Yes, sir. Then coming southeast from Caroline to Mouncie, Saskatchewan, you have another 42 inch pipeline?

A That's correct.

Q Which at the fifth year volumes would meet your test of transportation of gas

at minimum unit cost?

A Yes, it does.

Q Given the volumes that the client gave to you?

A That's correct.

Q And for that leg, did you design the 42 inch to fit the volumes, or were you given the volumes and the pipe size by the client?

A We were given the volumes and the pipe size and as the application states, we located compressor stations so that the optimum volume could be achieved in that section of the pipeline. The optimum volume, I think the application says is 2.7 billion cubic feet. It's slightly higher than the 2.1. billion that is being carried.

Q Well, Mr. Purcell, then can we conclude this portion by saying that the design --insofar as the design is capacity, the system from Prudhoe Bay to the 49th parallel was given to you by your client? You were told the pipe sizes to use from end to end?

A We were told the pipe sizes to use from end to end, yes.

Q Then sir, if you're going to optimize or provide the minimum unit cost for the transportation of gas through the two northern supply lines, one from Prudhoe Bay and one from Richards Island, you're going to end up carrying through each of those supply lines, approximately four and a half billion cubic feet per day, are you

not?

A Each of the supply lines has that capacity.

Q And operated at that capacity would provide the minimum unit cost of transportation?

A Thats correct.

Q And when that point is reached, if ever, are you not then forced to loop the section south of Travaillant Lake?

A Yes, sir.

Q Yes. And do you have any advice to offer the inquiry on when that might occur?

A We have received no instructions to proceed with plans for looping the pipeline south of Travaillant Lake junction, or for that matter, for any of the segments of the pipeline system.

Q Have you done any independent design work towards a looping program, regardless of whether you have client's instructions or not?

A We have in some cost studies we have made, considered the effect of going beyond the gas volumes shown in the book. For example, at one point we looked at the economics of a 42 inch alternative to the main line south of Travaillant Lake Junction, and to reach the same gas volumes it was necessary to loop that 42 inch line.

So some of our studies have

included it, but they have not been serious alternatives proposed by Canadian Arctic Gas.

Q In your contacts with the producers in determining gas composition, did you give any -- pay any attention to the deliverability from Prudhoe Bay and from the Beaufort Basin?

A The ability of the fields to produce the gas?

Q Yes?

A No sir, that was outside the scope of Northern Engineering's work. That was handled directly by Canadian Arctic Gas.

Q You are not then able to tell the Commissioner whether there is projected a daily deliverability greater than the two and a quarter billion cubic feet per day through the Prudhoe Bay and Richards Island supply line?

A I can't speak to that, Mr. Gibbs. I think there is a volume that has been submitted that does cover that subject.

Q And have you examined that volume?

A I've glanced at it, that's all. I haven't read it carefully and I certainly can't support it.

Q Mr. Purcell, have you assumed or were you told by your client that the two decimal one one two billion cubic feet per day going south-east from Caroline to Mouncie would all go to the 49th Parallel?

MR. MARSHALL: Mr. Commissioner, I think here again we're getting into a question of the subject that is within the jurisdiction of the National Energy Board, and really has no bearing on this Inquiry.

MR. GIBBS: Well, sir, there is something in excess of 100 miles of pipeline in Saskatchewan that sure isn't going to be needed if the gas goes into Trans-Canada Pipeline, and I was about to ask him about his sizing of that section.

THE COMMISSIONER: Excuse me, the -- this is the continental delivery system may?

MR. GIBBS: Yes sir.

THE COMMISSIONER: Well, if it is designed to get at the question of looping -- is it not?

MR. GIBBS: No, it was getting back again to how much of this pipeline, what kind of a design he would put from Empress, Alberta, to Mouncie, Saskatchewan, if he were designing it on the assumption that some portion of that gas went into the Trans-Canada Pipeline. But I don't need to pursue it, he's already agreed with me that the client told him what size of pipe to use.

Q Mr. Purcell, can we now turn to the gas composition portion of Exhibit 54, which is, I think, under tab 2, it's under tab 8-B, pink tab 2 form and assumptions page 12.

A I have it here, yes sir.

Q I take it, sir, that there is no way of saying at this point in time that the Prudhoe Bay and Richards Island gas streams will be of the composition there shown.

A They are the best estimate that can be made at this time of the composition.

Q But in each case, Mr. Purcell, does it not depend upon designing a processing plant?

A I'm not an expert in these things, Mr. Gibbs. I think the primary variable would be the reservoir fluid composition. I think the characteristics of a gas plant are fairly well known by the gas producers.

Q Yes sir, but you and I have been involved in the industry long enough to know that first of all the gas plant has got to be designed.

A Yes sir.

Q And then it has to be approved by some regulatory authority.

A I'm not -- I don't know that that's true. I'll take your word for that.

Q And then it has to be built.

A Yes.

Q And in its design you can vary the -- I think it's called the cut -- to determine how much of the gas composition will be liquids at atmospheric pressure.

A You can operate a given gas plant at slightly different temperatures to achieve a different gas composition.

Q Yes, so then the Prudhoe Bay gas stream, its ultimate composition will depend upon the configuration of the plant that's built there, and the conditions, if any, imposed upon its construction by regulatory authorities in Alaska, and the operating temperatures and operating procedures.

A Yes sir.

MR. MARSHALL: Well, Mr. Commissioner, this is clearly an area where the witness doesn't have personal knowledge. Mr. Gibbs is suggesting various regulatory authorities, unidentified, and he's not been specific on this point. The witness has indicated that he's not an expert in the subject.

MR. GIBBS: The panel is supposed to be able to talk about this portion of Exhibit 54, design and capacity.

THE COMMISSIONER: The witness agreed with you. If it turns out he's not equipped to offer an answer, I'm certain that he'll say so.

MR. GIBBS: Q Now, Mr. Purcell, what I call the liquids content which -- by which I mean

the liquids which will become liquid at atmospheric pressure, is considerably higher in the Prudhoe Bay gas than it is in the Richards Island gas, is it not?

A Would you repeat the question? What is higher?

Q The liquid content. Perhaps, Mr. Purcell, we could go it this way. Am I correct in saying that the gas components which will become liquid at atmospheric pressure are the pentanes and the hexanes?

A And heavier, yes.

Q And that that liquid volume in Prudhoe Bay is about 22% higher than it is in Richards Island.

A According to my calculations it's, in the case of Prudhoe Bay, .22 mole percent, and in the case of Richards Island, .18 mole percent.

Q And the difference is about 22%.

THE COMMISSIONER: An earlier witness, Mr. Purcell, an earlier witness, Mr. Bailey, said that the Mackenzie Delta gas was, I think he called it, clean gas, and he said the Prudhoe Bay gas was -- and I think once again he said -- sour gas. Do those terms mean anything to you?

A I think he said the Richards Island gas was lean, L-E-A-N.

Q All right, lean and sour.

A No sir, neither of these gases is a sour gas.

Q Well, all right, lean describes the gas in the Mackenzie Delta certainly, Richards Island. Would there be any expression approximating the phrase "sour gas" that would apply to the Prudhoe Bay gas?

A Both these gases would be called sweet as opposed to sour. The Prudhoe Bay gas would be called rich as opposed to lean. It's primarily the components of ethane and propane and butane that contribute to the extra heating value of the Prudhoe Bay gas.

Q And Mr. Purcell, the reason why this is not sour gas is that fortunately there's no sulphur in it.

A Yes sir, very little at any rate.

Q Well, I'm sorry to interrupt you, Mr. Gibbs, but just so I understand this, Iwish I had Mr. Bailey's evidence before me, but I got the impression -- maybe I shouldn't have -- that the Richards Island gas would not require to be processed to the same extent as the Prudhoe Bay gas to make it acceptable to the trunk pipeline. Is that -- does that make any sense to you, or have I simply misunderstood?

A I think they plan to process it. I think you may be right in that they will have fewer liquids to dispose of that cannot be carried

by the gas pipeline. In the case of the Prudhoe Bay producers, those liquids that they can't use in the gas pipeline and they can't use for fuel, I understand they are able to accommodate in their oil pipeline.

MR.GIBBS: Q Mr. Purcell, the higher liquid content in the Prudhoe Bay gas is of significance, is it not, if the pipeline goes through a decompression phase, if the pressure drops in the pipeline?

A The composition of the gas affects the way it decompresses.

Q Yes sir and if it decompresses down to atmospheric pressure, the liquids drop out of the gaseous stage and become liquid in the lower portions of the pipeline.

A I suspect there would be some liquid in the pipeline if it was completely decompressed.

Q Well, sir, I am advised that if a fracture occurred in that Prudhoe Bay section, the section west of Travaillant Lake, and there was a rapid decompression as a result, you could get in the 45 or 55 -- 50 miles between compressor stations, a dropout of as much as 1,000 barrels of liquid. Do you agree or disagree?

A I have no information to agree or disagree.

Q Does anyone on the panel

know anything about that?

WITNESS KING: I would suggest that many of these liquids, the pentanes and hexanes that you talk about, would evaporate along with the methane. There's afamily similarity between these substances and in a mixture of natural gases, the methane enables the pentane and hexanes to evaporate.

Q But whether or not they evaporate or become liquids in the lower parts of the pipelines, depends, does it not, on the rate of decompression and the temperature and other factors of that sort?

A In our studies of the phase envelopes of these gases, at atmospheric conditions there are no liquids at atmospheric pressures and atmospheric temperatures; there are no liquids which remain after decompression.

Q Would you repeat that?

A Maybe some explanation might help. If you have pure hexane, it will be a liquid at atmospheric conditions. If you have a mixture of methane and hexane, the mixture will be a gas at atmospheric conditions.

THE COMMISSIONER: I see.

A For example, water is normally a liquid at atmospheric conditions, and yet in this room we have many gallons of water entrained as a gas in atmosphere, and yet we have no free liquid.

THE COMMISSIONER: Well, Mr. Gibbs' suggestion to you then, Is I take it that at atmospheric pressure the pentanes and hexanes will liquefy and that a rupture in the Prudhoe Bay leg of this pipeline would drop out of the pipeline in the form of liquids?

If they did, what would their properties be? Is it just like a thousand barrels of

water or is it toxic? What is this likely to result in, if it did occur, and I appreciate that you deny the suggestion made by Mr.Gibbs that it would be likely to occur.

A They would have an appearance of a very light oil, extremely light oil.

Q With the same properties?

A Similar properties, yes.

The other thing that I would like to point out is that the two gases in question have very similar characteristics, very similar quantities of the heavier components. For instance, -- in fact, the Richards Island Gas is slightly richer in hexanes and hectanes. It's very hard to distinguish between these two gases in heavy components.

MR. GIBBS:

Q Well sir, is it your evidence that there will not be a liquid drop-out if there is decompression in any portion of that pipeline?

A There could be small amounts of liquid drop-out, but certainly not the quantities which you talk about. Much of it would be carried into the atmosphere by the methane gas.

Q And what quantities do you suggest might drop out in the 50 mile section between compressor stations?

A I was suggesting that there would be none at all, sir.

Q There would be none at all?

A No, sir.

Q Under any decompression circumstances there would be no liquid drop-out?

A At extremely low temperatures there may be some liquids remaining in the pipeline, sir.

Q And by that do you mean in the permafrost areas?

A The temperatures which may occur after decompression. The liquids will contain a large amount of methane, and I would expect them to evaporate when the pipeline returns to the atmospheric temperature and atmospheric pressures, that all the liquids would evaporate.

Q Atmospheric pressure meaning the -- what do they call it, the ambient pressure?

A Yes, 14.7 pounds per square inch.

Q I'm sorry, temperature?

A Say around-30 or 40 degrees.

Q And that's your evidence, that we needn't concern ourselves with liquid drop-out if there is a decompression in any of those sections?

A That's correct, sir.

Q All right. Now sir, on the same page there is a comparison of heating values. Do you see that, Mr. Purcell?

WITNESS PURCELL:

A Yes, sir.

Q And the heating value of the

Prudhoe Bay gas is approximately 10 percent greater than the Richards Island gas?

A That's correct.

Q And that's partly what's meant by saying that the Prudhoe Bay gas is richer?

A Yes, sir.

Q And do you incorporate anything in your design to enable calculation of the precise difference in heating value for compensation purposes?

A In terms of delivering the gas at the end of the pipeline?

Q Yes.

MR. MARSHALL: WELL, Mr. Commissioner, I think this gets into an area of establishing the tariffs and so on, and again it's an area that would involve others in the Arctic Gas organization, and perhaps another forum.

MR. GIBBS: Well sir, the query that when the gas is mixed, the Canadian gas ends up about five percent richer than when it was not mixed, and clearly if you are going to buy and sell on a BTU basis you're going to have to pay for it, because you're getting a better cubic foot of gas. And I am merely asking whether he put anything into his design to measure that at the delivery point, so you can determine the heating values there.

THE COMMISSIONER: I think that Mr. Marshall's objection was not on the grounds of relevancy, but simply of the ground that these

witnesses weren't qualified to deal with the issue.

MR. MARSHALL: Strictly from a design point of view as to whether such -- something has been incorporated within the design, the witnesses can answer that, sir. Going beyond that point, though, I think I would have to raise an objection again.

THE COMMISSIONER: Well I think that you are entitled to carry on, Mr. Gibbs. As far as the knowledge of these witnesses will allow, and --

MR. GIBBS: Well that was my sole question, is whether he incorporated anything into the design so that these can be measured and appropriate compensation determined.

A Our measurement stations provide facilities to measure the heating value of the gas, so that adjustments of that nature could be made.

Q And are these measurements done at each compressor, or at specified points on the line?

A They're I think described in the application. There would be two -- there would be a measurement station at each point the pipeline receives gas.

Q Okay.

A There would be another one near the Alberta/Yukon border, because you're transferring gas from one company to another.

Q Alberta/B.C. border.

A I'm sorry, the Alaska and Yukon border. And there would be a measurement station at each point of gas delivery. We don't contemplate a full measurement station at each compressor station.

Q Thank you. Would you turn now back to your prepared evidence again, sir, and particularly to page 5. And I direct your attention to the second last sentence which is the second of your major objectives. You began that paragraph by saying,

"I established three major objectives for the design group,"

and the second was that present day technology should be used.

"We were not to consider in the design, future technological advances which might take place".

And am I right, sir, in assuming that you would adhere to that objective throughout the whole of your design?

A I believe we have.

Q And you're satisfied as you sit there, that only present day technology has been used in your design?

A Yes, sir.

Q Would you define for me, sir, your understanding of the words "present day

technology"?

A It refers to materials that for example could be purchased today. Purchase orders could be placed for the equipment that is proposed today. And pipe mills or other manufacturing facilities could produce these components.

Q Technology then in your concept refers to the ingredients of the equipment?

A The ingredients and the manufacturing processes and so forth.

Q Does it have any geographic connotation?

A I don't understand.

Q Well if you read in a Russian magazine that they were using some technique in Russia that had not been used here, would you call that present day technology?

A Yes, I think I would.

Q Even though you might not have access to it?

A We would not incorporate it in the designs if we were not familiar with it, and would not have access to it.

Q And I take it that in your design work you have not incorporated anything that you have not had access to?

A Not to my knowledge.

Q All right, sir. Now, I am about to suggest to you some features that to me at least don't seem to be in accordance with your

present day technology test. Is there anywhere, sir, in North America to start with, where 48 inch outside diameter pipe is being used to transport natural gas?

A I think not, Mr. Gibbs.

Q Is there anywhere in North America, sir, where pipe with a wall thickness of .720 inches is being used to transport natural gas?

A Not as a mainline. Such pipe would exist today in compressor stations.

Q Is there anywhere in North American where a natural gas pipeline is operating at a pressure of 1,680 pounds per square inch gauge?

A I think again not for a natural gas transmission pipeline, but such facilities do exist at gas processing plants. Pressures much higher than that are common.

Q Then wouldn't you agree with me then, sir, that those three items at least are not present-day technology?

A No sir, I would not.

Q All right. Then I ask you to consider the combination of four items, 48-inch outside diameter,grade 70, .720 inch wall thickness, at 1,680 pounds per square inch gauge and ask you if that package is not new technology?

A There is not a pipeline today that has those characteristics, that's why we've spent five years studying the project to be sure that it's a good design.

Q And doesn't present-day technology also have incorporated in it an experience

factor?

A Yes.

Q And there is no experience with that combination in North America, or even in the world, is there?

A There again, there is to my knowledge no pipeline of this size in the world.

Q Or of that package combination of diameter, thickness, grade and pressure.

A That's correct.

THE COMMISSIONER: Is that the grade of steel?

A Yes sir.

MR. GIBBS: Q So that your, if I can call it, a package again, is not present-day technology, is it?

A The intent of that statement, Mr. Gibbs, was that when we came before Mr. Berger or if we can before the National Energy Board we would be able to demonstrate that we could get pipe of this size and we would be able to demonstrate that we anticipated any problems that could arise because of the scale of this project. That's what I meant when I wrote that down.

Q You didn't --

A I didn't mean that we had to follow something that had already been built. There is no precedent for a pipeline of this length in permafrost to start with, it wouldn't have been

possible.

Q Oh yes, but we're not talking about length in permafrost now, we're talking about wall thickness, diameter, and operating pressure and grade. You, I take it, didn't mean in your words, "present-day technology" that it wasn't something new.

A No, I agree with you that this is a new combination of factors for a pipeline.

Q And a new combination of factors for a pipeline anywhere in the world.

A Yes sir.

Q Now sir, can you turn to page 23 of your prepared evidence. You talk about your fracture arresting techniques. On page 22 at the bottom you said that:

"The fracture arrest behaviour of the proposed mainline pipe at the designed temperature and pressure cannot be consistently predicted by the Battelle hypothesis."

A I did.

Q And then on the top of page 23, you say:

"Therefore our design is based on adding mechanical reinforcing bands or similar devices at suitable spacings along the pipeline to assure control over the length of a possible fracture. Three separate tests were made to show that reinforcing bands can be used in the remote event of a fracture, to control the

length of the fracture."

Firstly,sir, will you describe for the Commissioner the size and shape and configuration and composition of the arresting band or reinforcing bands you talk about?

A We have several alternatives available to us.

Q But before you describe all those alternatives, have you made a choice that you're going to use in this pipe?

A We know of one design -- the one that has been tested -- that we would be able to use if we had to start today. The program, I think, is to optimize that design and perhaps improve upon it.

Q The word "optimize", Mr. Purcell, when you use that you mean more efficient?

A More efficient in the sense, yes, of working better and perhaps being more economical.

Q Will you then describe the one that you would use were you building the pipeline today?

A The reinforcing band that we've tested was made of a piece of 48-inch pipe just the same as the line pipe . It was split in half, it was put on top of the pipe, the ends didn't join, obviously, so straps were welded over the gaps in these two halves.

Q How long is the band?

A I believe the ones that have been tested were four feet long.

Q And is that the length you will be using, were you building the pipeline today?

A That, I think so, yes.

Q And they are three-quarters of an inch thick? Or 0.72 inches thick?

A That's correct.

Q And under operating conditions how would you install them, by the welded band you've described, or would they be shrunk over the pipe, or how would you put them on?

A My view is that they would be installed in a shop, they would not be installed in the field. I believe that they would be installed at a location where we were perhaps double-jointing the pipe.

Q And would they then be sort of heat-shrunk onto the pipeline, or welded on, or how do you fasten to the pipe?

A They would probably be fastened to the pipeline by friction. They would be strapped down tight over the pipe and welded to themselves.

Q And would I be in the right range to suggest that if you use those 4-foot lengths, that each one of those will weigh approximately one ton?

A I think so, yes. No, they wouldn't either, they would weigh 1,000 pounds, I believe.

Q Half a ton?

A Yes.

Q And in what areas of the pipeline system from Prudhoe Bay to the 60th Parallel would you intend to install the arresting bands?

A I think if we had to build the pipeline today we would install them on the entire pipeline.

Q And at what frequency, what distance between each band?

A That hasn't been determined, Mr. Gibbs. My guess would be it would be something like a 300-foot spacing.

Q That must add substantially to the capital cost of your pipeline, doesn't it?

A No sir, it's very insignificant.

Q It is?

A Yes.

Q All right. Now sir, the purpose of those bands is to stop fractures which run lengthwise in the pipe.

A To be absolutely sure that they stop, yes.

Q And have those arresting bands been used in any existing pipeline system in

North America?

A No sir, Ithink we're just today reaching the point in pipeline design that it's becoming apparent that they're necessary.

Q But we can at this point in time say that there's no experience in the use of those bands, under operating conditions to arrest factors.

A I didn't hear the last part, Mr. Gibbs.

Q That there is no experience in the use of those bands under operating conditions to arrest these longitudinal fractures.

A For an operating pipeline, no. There have only been the full-scale tests that we conducted.

Q Now, where were your three separate tests conducted, Mr. Purcell?

A They were conducted at Battelle's facilities in Athens, Ohio.

Q And when were they conducted?

WITNESS HOLMBERG: These tests have been conducted over approximately the last year or 18 months.

Q That's the three that are referred to in the prepared evidence?

A Yes.

Q On three separate occasions over the last approximately 18 months or so.

A Yes.

Q And were they conducted under the supervision of Arctic Gas, or the Battelle Institute, or a combination of both?

A Combination of both.

Q And in the case of each test, were they conducted under simulated operating conditions?

A Simulated pressures, yes.

Q Simulated inside pressures?

A Simulated high pressures, yes.

Q But not simulated outside pressures, not buried in frozen ground,for example?

A The pipe was buried, but not in frozen ground. The last test was made in frozen -- at low temperatures at which the ground was partially frozen.

Q Was the fracture initiated in the same way in each case?

A Initiated?

a Yes?

A Yes.

Q How?

A This was initiated by cutting a notch of a predetermined size in the pipe, and then by an explosive, the small section at the root of the notch was overstressed, causing the pipes to rupture.

Q Well, meaning it cracked?

A That's right.

Q In each case was the same length of test section used?

A essentially the same lengths. There was some variations due to variations in pipe lengths.

Q Yes, sir. But in each case it was roughly 800 feet?

A I believe that's correct.

Q And in each case was the same pipe specs -- pipe of the same specifications used as is going to be used, as you propose to use in the Arctic Gas system?

A The tests were made using several different combinations of pipe available from different mills to obtain information on the effectiveness of the arrestors and also obtain other information on fracture speeds, fracture propagation characteristics of these different pipes. But they were all made on pipe of types that are being considered for use in the project.

Q Well they were all 48 inch, decimal 720 grade 7B --

A Yes.

Q -- and all of that character?

A Yes.

Q What was used to build up the pressure inside.

A Gas, natural gas.

Q And was it gas of the composition which we discussed earlier for the Prudhoe Bay and the Richards Island stream?

A Several different gas compositions were used in the tests, including gas compositions comparable to those that will be obtained from Prudhoe Bay.

Q And how far apart were the arresting bands on each of the three test cases?

A The -- this test is made by initiating a fracture, the fracture propagates in opposite directions, and --

Q In both directions at once?

A That's right.

And I have the information available, but I have to go from memory, but I believe the fractures propagated in opposite directions approximately 40 to 50 feet before they reach the band.

Q Do I take it then, sir, that in each case the arresting bands were in excess of 100 feet apart?

A Yes.

Q And in each case did the fractures run right to the bands?

A No, they did not in all tests.

However, there have been three instances where the arrestors did stop propagating cracks.

Q But in these three tests, Dr. Holmberg --

A It's Mr.

Q -- Mr. Holmberg, isn't it so that in only one case the fracture reached the arresting band?

A I don't believe that's correct. I'd have to review my notes and the data on the test.

Q And are those handy to you at this point?

A It will take me a little time to locate that information. I have it here, but --

Q How much is a little time?

A Possibly five or 10 minutes.

Q Well sir, perhaps I can go on to some other questions while you do it. I do want to deal with these during the course of this interchange.

A I'm sorry, I -- did you address something to me? I didn't hear.

Q I was sort of addressing it to the Commissioner and to you.

THE COMMISSIONER: Is it possible for you to find that reference to the tests now, over the next 5, 10, 15 minutes?

A I'll see if I can.

THE COMMISSIONER: Well you do that sir, and Mr. Gibbs will ask questions of your colleagues and we will just carry right on.

MR. GIBBS:

Q Mr. Purcell, will you turn to your prepared evidence at page 23, and I am interested in the question in the middle of the page. Have you satisfied yourself that steels suitable for this pipeline are commercially available? To which you answered "yes".

WITNESS PURCELL:

A That's correct.

Q Can you define for me, your understanding of the word "commercially"?

A Well by that I mean it's available in the quantities that we require and at a price that we can afford.

Q At this time?

A Yes, sir.

Q Given a reasonable lead time of --

A Given time to place orders and time for the steel mill to get ready.

Q Five or six months?

A I think a year might be more appropriate.

Q And when they talk about steel suitable for this pipeline, that is plate 40 feet long and twelve and a half feet wide and decimal 720 inches thick, and the chemical composition that you require?

A Yes.

Q Where is it available commercially, sir?

A The pipe can be made in Canada, it can be made by one pipe mill in Canada, 48 inch pipe. It can be made by four pipe mills in Japan, one pipe mill in Germany, and one pipe mill in Italy.

Q And in each of those cases

you could obtain that pipe commercially and you expect about a one year lead time on orders?

A Yes.

Q And you referred to one pipe mill in Canada, and that's Stelco?

A Yes, sir.

THE COMMISSONER: Sorry, what was that?

A Stelco, the Steel Company of Canada.

THE COMMISSIONER: Stelco.

MR. GIBBS:

Q I understand sir, that in terms of reliability is somewhat less reliable than the pipe which is made offshore in Japan or Germany or Italy?

A I don't understand that.

Q Well sir, I asked for -- when I saw that question -- some education on the availability of this kind of pipe, and I am just going to read you a little bit of information that was passed to me for my education, and ask you if you agree with it.

MR. MARSHALL: Is this a report that you're referring to? I wonder if you could -- or is this some instructions from your client?

MR. GIBBS: No, I'm just going to read him what I'm told and see if he agrees or disagrees.

And this is a purported grading

of pipe manufacturers with future capability in sort of order of priority, and I'm told that in the first order,Mannesman, Nippon Steel and Sumitomo, and those are one German and two Japanese outfits.

THE COMMISSIONER: Excuse me, Mr. Gibbs, can I ask you, does this relate to the quality of the pipe produced in these mills, or does it relate to their reliability so far as their capacity to deliver on schedule is concerned, or what?

MR. GIBBS:No, not delivery, the actual making of the steel and the rolling it into pipe.

And number 1 it says mannesman, Nippon Steel and Sumitomo were all judged equally capable of presently supplying controlled rolled line pipe meeting our specification requirements, and that would still be the case would it?

A That would be true in my opinion.

Q In your opinion. The second one says Italside, I-t-a-l-s-i-d-er, and that's Italian, I take it?

A Yes, sir.

Q Has indicated the capability of producing line pipe to the requirements of our specification, however the lack of experience this company has in the production of high toughness line pipe and the limited amount of production data available, results in them being judged fourth best in production capability. Would you agree with that?

A I would like to ask Mr. Holmberg. I think he's more familiar with the various pipe mills than I am.

MR. GIBBS: I am sorry. I didn't want to interrupt him in his search.

MR. MARSHALL: Mr. Commissioner, Mr. Holmberg I think is interested in these subject areas, and he's unable to search through his material to find the data that had been requested by Mr. Gibbs.

Further, with respect to this line of questioning being pursued by Mr. Gibbs, I might ask whether he is giving evidence or he is quoting from a report or what. It seems to me fair to have him identify what it is he is reading from at some length.

THE COMMISSIONER: He's entitled to say, my instructions are that these companies should be rated on this basis, one, two, three, four.

Now, he really isn't obliged to go any further than that.

MR. MARSHALL: That's fine, if we are dealing with his instructions, sir. I quite agree.

MR. GIBBS:
Q I wonder, sir, if Dr. Holmberg has got any further in getting to his test material? I don't want to interrupt him but I have two lines of questions now that are waiting.

THE COMMISSIONER: Well, I think Mr. Holmberg, if you are needed on this current line of questioning, you might as well give up the search for the test data for the moment. I think to be fair to Mr. Purcell that should be done.

Yes, Mr. Scott?

MR. SCOTT: Would it help to take five minutes, and Mr. Gibbs has now got onto two lines of questioning, both of which seem to require the same witness.

THE COMMISSIONER: Dual lines of questioning.

MR. SCOTT: Dual lines. Twin lines.

THE COMMISSIONER: We'll take a five minute break then, and you can do what you can.

(PROCEEDINGS ADJOURNED FOR FIVE MINUTES)

(PROCEEDINGS RESUMED PURSUANT TO ADJOURNMENT)

MR. MARSHALL: Mr. Commissioner, I believe Mr. Holmberg has found the data pertaining to two of the tests. If that would be of assistance to Mr. Gibbs we could have it now; if he'd rather wait until he's got the information on all three tests, I'm afraid we'll have to wait till tomorrow.

or allow Mr. Holmberg a few more minutes to do some more work.

MR. GIBBS: I prefer to have it tomorrow, sir, if it's going to take that, and continue with the line I'm on now.

Q Then, Mr. Purcell, the report I have goes on to say that

"N.K.K."

that's a Japanese firm, is it not?

A Yes sir.

Q

"-- was judged least capable of the mills in this grouping and they took exception to several major areas of the specifications."

Would you agree ~~that~~ that is still the case?

A What's the date of your report, Mr. Gibbs?

Q April of 1973, sir.

A Again I'd like to defer to Mr. Holmberg.

WITNESS HOLMBERG: I'm not sure exactly what your question is, I'm sorry.

Q Well, I had told, while you were searching there, that Mr. Purcell that I asked for and had a report listing in order, not priorities, suitability of the available pipe manufacturers of the steel which Mr. Purcell said is commercially available, and that in order of -- for want of a better word, priority, I suppose one might say reliability or

something of that nature they occurred first category was Mannesman, Nippon Steel and Sumitomo.

MR. MARSHALL: Mr. Commissioner, I hesitate to make a pest of myself on this point but it seems to me that Mr. Gibbs is referring to a report of April, 1973. If he's putting forward an expert's opinion and he's asking the witnesses whether or not they agree with it, it seems to me the expert being quoted ought to be identified so that they'll know what they are dealing with. On the other hand, if it represents instructions he has from his client, I quite agree that provided it's put forward on this basis there is no objection to the line of questioning. I would just like the point clarified by Mr. Gibbs.

MR. GIBBS: Well sir, in my submission I am entitled to put to these witnesses this category of preference. If they disagree they will say so. If they agree they will say so.

THE COMMISSIONER: Well, I think that you are entitled to do that, Mr. Gibbs. But you have gone beyond simply saying to the witness, " I put it to you that in order of reliability these firms ought to be rated No. 1, No, 2, and so on." You have now said, "I have a report," and you're really in a sense stacking that report up against the opinion ofMr. Purcell and his colleague, Mr. Holmberg, and I maybe in somewhat a different position now that you've gone that far.

MR. GIBBS: Well, sir I didn't

think my friend would really want it marked as an exhibit, and I'm quite prepared to tell him what it is. It's the Minutes of the Sub-Committee, of the Metallurgy Sub-Committee for April, 1973 of which Dr. Holmberg at least was a member. Certainly those are within his possession as well as within mine.

MR. SCOTT: Perhaps now that it has been referred to it had better be marked as an exhibit.

MR. GIBBS: What I have is just an excerpt. I will get the full set of Minutes and have them brought up, if that is your direction, sir.

THE COMMISSIONER: Yes, subject to any objection you may have, Mr. Marshall.

MR. MARSHALL: It's a document that Mr. Gibbs has in his possession and wishes to put in as an exhibit.

MR. GIBBS: No, I don't wish to put it in. It was suggested by Mr. Scott that it go in.

THE COMMISSIONER: Well, Mr. Scott suggested that it ought to be marked as an exhibit. I agree, so that I am directing that Mr. Gibbs produce a copy, and he says he will, and when he has produced it, I will direct that it be marked. So as I say, subject to any objection that you may have, since it's a document originating, I take it, with your client, or with Arctic Gas.

MR. MARSHALL: We take no position on that point, sir.

MR. GIBBS: It will take a day or so to produce the entire set of Minutes, sir, but I can -- assuming I have access to xerox facilities, xerox the excerpts I have and distribute them tomorrow, and then later file the entire set of minutes.

THE COMMISSIONER: All right.

MR. GIBBS: Q Now, Mr. Holmberg, would you agree that today that sort of rating order would still put Mannesman, Nippon Steel, and Sumitomo equally and probably best capable of supplying the pipe to meet the specifications?

A They are still all capable, I don't know as I would necessarily rate them in exactly that same order.

Q And -- I'm sorry.

A I believe the Minutes of the meeting that you're referring to is a Minute or a meeting that was held, I believe, in Calgary, at which time all of the steel companies in the world that were prepared to furnish pipe or were considering furnishing pipe for this project were invited to attend. They had a series of meetings at which they reviewed the specifications in detail, the areas where they had problems complying with the specifications, and a mutual exchange of trying to reconcile what they could do with what we wanted, and I don't remember the exact rating or that we actually put a specific rating on the mills.

I don't question that it was done but I don't recall that.

Q Well, sir, I'm reading from these Minutes. Perhaps it would help, Mr. Holmberg, if I read the opening paragraph under the heading,

"Pipe Manufacturers."

"Meetings were held with nine major pipe manufacturers with either present or future capabilities of supplying pipe for the project. On the basis of the presentations made and data presented, the metallurgy sub-committee determined a relative ranking of the capabilities of these manufacturers to produce pipe meeting the requirements of the material specifications. The companies are ranked in two groups, those with existing mill facilities, and those with mill facilities in the planning or construction stage."

Then they rank them in order, and order No. 1 is Mannesman, Nippon Steel, and Sumitomo.

A This was on the basis of present facilities, is that correct?

Q Yes sir, and would you still rate them No. 1 on the basis of present facilities?

A I'm not sure that I would, and I don't know that it makes a whole lot of difference. The reason that I'm a little hesitant in saying that I'd rate them this way is that during the past two years the Japanese have made additions to their, both their

steel mills and their pipe mills, and have greater capability than they had at that time. I'm not prepared to say that I'd change the rating but I don't think this rating is really very critical as far as the pipe being available from those several mills.

Q Then let me read you from these minutes, the comment on Italsider.

MR. MARSHALL: Well Mr. Commissioner --

MR. GIBBS:

Q That's the right pronunciation, is it?

A That's correct.

MR. MARSHALL: -- I think I must register my views on this. Frankly, I can't see where this is taking us in terms of relevancy. Perhaps Mr. Gibbs can be helpful on that point and demonstrate --

MR. GIBBS: Well sir, I began with his own question, steels suitable for this pipeline are commercially available. And in the --the comment on Italsider says that they have indicated the capability of producing the line pipe to the requirements of our specifications, however the lack of experience of this company in the production of high toughness line sites and the limited amount of production data available, resulted in Italsider being judged fourth best in production capability.

Q Would you still adopt that type of classification?

A I'm not sure that I would asfar as Italsider is concerned. Since then, they've gained a large amount of additional experience. They are presently furnishing a large amount of pipe to Russia, and some of the people that have

visited the mill have been very well impressed with their capabilities.

Q All right, sir. Number 3 is NKK, which I understand to be a Japanese company?

A Yes.

Q And the minutes say,

"On the basis of the presentation made to the subcommittee was judged least capable of the mills in this category".

Then the report goes on to refer to their objections to the specifications, and then it says it is noted that with the mill capabilities and previous experience of NKK, they would be expectedto rate higher in this evaluation, and that their response on this occasion may have been part of the strategy of the Japanese consortium to determine their technical position with respect to other world bidders.

Now, would you still rate NKK as least capable of the mills in this category of those with present facilities?

A I don't know that I would change it. I would like to say, however, that following that meeting at which NKK gave very incomplete information,they conducted a large amount of testing, submitted a large amount of additional information that indicated that they were capable of providing pipe to meet the specifications.

Q Then under the heading "Potential Future Suppliers", number one is Hoesch,

H-o-e-s-c-h, German, I take it?

A Would you spell that again? Are you sure it isn't Hoesch, H-o-e --

Q H-o-e-s-c-h-?

A Yes, Hoesch, yes.

Q It's called Hoesch, and that's German?

A Yes.

Q Hoesch have shown experimental data that indicates that they will be able to make spiral welded pipe meeting the requirements of the specification with the completion of mill modifications presently being undertaken. They are potentially capable of supplying only a small portion of the line pipe for the project, due to limited capacity of their mills, and is that still the case with Hoesch?

A Since then they have increased their capabilities, but they are still prepared to only furnish a limited amount of pipe.

Q I see. They have gone through the mill modifications to meet the specs, but they still have a limited production available?

A That's right.

Q Then U.S. Steel, an American company, is that correct?

A Yes.

Q U.S. Steel took numerous exceptions to the specifications, but have indicated that they have the technical capability of making the

steel required. At present, however, they have no firm plans to modify their mill in order to produce 48 inch diameter pipe. Is that still the circumstance?

A Whether they have reached a definite decision that they will modify their mill to make 48 inch diameter pipe, I've had conflicting reports. I really don't know for certain that they have made the decision to go ahead with that change.

Q As of today, we don't know whether we could look to them for any of the pipe or not?

A We can't rely on it as of today.

Q Then Stelco, Steel Company of Canada which is a Canadian company?

A Yes.

Q Stelco has not yet demonstrated the capability of making steel with the required strength and toughness in their plate mill.

THE COMMISSIONER: In their what?

MR. GIBBS: Plate mill.

Q Their spiral mill is scheduled for completion and production of trial pipes in January, 1974. Their ability to furnish pipe meeting our specifications is dependent primarily on their ability to develop the necessary technical know-how at the plate stage, rather than

the mechanical problems associated with the pipe mill. Is that still the case?

A Not entirely. They have made pipe that except for a few details, complied with the specifications. We have tested some of this pipe, and discussions with them indicate they have several alternates as far as improving their steel making ability to meet the specifications.

Q And have they, sir, produced what I would call a production run as against joints of pipe for testing, to meet the Canadian Arctic Gas specifications?

A As far as making production runs, I don't know. I don't believe they have.

Q No, and that particular mill which was to be completed in January, 1974 is now --

A I think they have made some production runs on that mill, but I don't believe they have been production runs on pipe complying with our specifications.

Q No, it's been a different kind of pipe, thinner wall or smaller diameter, or something like that?

A Yes.

Q Some more conventional kind of pipe?

A Yes.

Q And then item 4 is IPSCO, and which is Interprovincial Steel Company, and

a Canadian company, to your knowledge?

A Yes.

Q IPSCO has indicated the capability of supplying smaller diameter pipe, 30 inch, required in the project with the required strength and toughness properties. No decision is anticipated for a year or more on a future expansion of their steel and pipe making facilities to produce 48 inch, zero decimal 720 inch wall thickness line pipe, and is that still the circumstance with IPSCO?

A I believe it is. At the time of that meeting, they indicated that if the project were approved and certainly that the line would be built, that they were prepared to make the investment and make the changes to the mill, so that they would have the capability of making pipe of the sizes we require.

Q That's subject to quite a lot of "ifs" though, isn't it? You wouldn't rely very heavily on them as a supplier?

A No I wouldn't.

Q No.

A Not at the present, at least.

Q Then number 5 is Kawasaki, K-a-w-a-s-a-ki, which is I understand a Japanese firm?

A Yes.

Q And it says not included in the meetings. It then goes on, is constructing a

new large diameter mill, but has not yet produced any pipe and their future capabilities are yet to be demonstrated, and is that still the case?

A That was true at that time, yes.

Q Now sir, can we sum all of that up by saying that if you were going to build that pipeline today, you really would have to go to the Japanese and German mills for the pipe?

A Not entirely. I believe that Stelco has made their -- has done enough development work that by the time we would be prepared to place orders, that we could place orders with them with confidence for a large quantity of the pipe.

Q Well perhaps I can qualify it by saying this, if you restricted your orders to those companies who have made production runs of 48 inch steel, of zero 720 inch wall thickness and who have therefore experience, you would be restricted to Japanese and German mills, would you not?

A On that assumption, yes.

Q Yes.

MR. MARSHALL: You're talking about building the line today are you, Mr. Gibbs, was that the context that you were speaking?

MR. GIBBS: I believe that's what I asked him in the question.

A I think it should be made clear, however, that this work with the different steel mills and potential pipe suppliers, was to make

them aware of what our requirements were, so that they in turn would be able to get in a position to furnish pipe, and of course this is one of the things that Stelco has positively done, and we intend to and are cooperating with them in every way possible with the expectation that they would be an important supplier.

Q Oh yes, I am sure you want it, if possible, that Stelco supply some of the pipe?

A Yes.

Q But then the question is whether Stelco are in the long run going to be capable of doing so? Capable of meeting your specifications?

A Yes.

Q Now sir, would you turn to page 36 of your prepared evidence, and in particular paragraph 2 on that page, which says:

"In discussions with the manufacturers,"

and I take it those are those manufacturers we've just discussed, the German, the Japenese, the Canadian and U.S. Steel?

A Yes.

Q Yes.

"In discussion with the manufacturers the sub-committee indicated the need for evidence that the specifications could be met, especially with regard to the requirements that were more stringent than in other specifications. In many cases the manufacturers rolled pipe and fabricated pipeline components to our specifications so that tests could be made to verify that the specification requirements had been met."

Which manufacturers rolled for you, sir, so that you could make those tests?

WITNESS HOLMBERG: We have tested pipe from Sumitomo, Mannesman, N.S.C. (Nippon Steel Company), and I think N.K.K., and Stelco Pipe.

Q What kind of tests?

A These have included the usual mechanical tests, notch toughness tests, burst tests on the pipe, of two types, one of which is referred to as the West Jefferson type of test in which the transition temperature of the pipe is checked against

the transition temperature as determined by laboratory tests, and then the Athens type test in which the pipe is tested with gas at that the pressures to be used in the line, a fracture initiated, and caused to propagate.

Q And were these in every case 40-foot joints?

A Essentially 40-foot joints. Some of the -- well, I should say in most cases they were probably a little under 40-foot because part of the pipe was used in making laboratory tests, welding tests and things of that type.

Q And those tests, Mr. Holmberg, demonstrated to your satisfaction that those four or five companies had produced in the test pipe that they delivered to you, pipe which met your requirements.

A The test pipe that was furnished did not always completely comply with our specifications, and meet our requirements. However, in most cases they were very close to it, and there is every reason to believe that with modifications in their operations that they will have no problem producing pipe to meet our specifications.

It should be kept in mind that in making pipe for these tests, that it's been necessary to provide pipe meeting the specifications or attempt to provide pipe meeting the specifications and producing only a small amount of pipe and the

mills did not have the opportunity to build up the background of experience in all cases but they succeeded in the time requirements that we placed on obtaining pipe to fully meet our specifications.

Q And Mr. Holmberg, would I be using a correct description if I referred to the pipe which was delivered to you for testing as a sample?

A As what? I didn't get that word.

Q A sample.

A As an example?

Q As a sample.

A Oh, as a sample, yes.

Q All right, sir. Do you know how many joints were rejected by Stelco before they produced a sample which they could deliver to you for testing?

A I have seen that figure but I don't know.

Q A large number of joints, I suggest to you, sir?

A Yes.

Q Which demonstrates that at that point in time they weren't very ready for a production run of a pipe of your specs.

A That is right, and not surprising.

MR. GIBBS: This would be a convenient time, sir.

THE COMMISSIONER: The question then is whether we are going to continue this afternoon. Mr. Gibbs is willing to -- what is the view of others?

MR. SCOTT: The poll is, Mr. Commissioner, that as far as the other participants are concerned, they require some preparation time. The question is how long this afternoon? Is Mr. Gibbs able to help us?

MR. GIBBS: Oh, I should think, sir, perhaps an hour, hour and a half, something in that -- I am content to do it this afternoon or tomorrow morning.

MR. SCOTT: Well then, this afternoon for an hour or hour and a half, I gather, would be satisfactory.

THE COMMISSIONER: Well, let's adjourn then until 2:30 and we'll start again at 2:30, for perhaps an hour, hour and a half.

(PROCEEDINGS ADJOURNED TO 2:30 P.M.)

(PROCEEDINGS RESUMED PURSUANT TO ADJOURNMENT)

MR. MARSHALL: Mr. Gibbs, you had asked Mr. Holmberg to obtain some information for you pertaining to these tests. He's dug that up over the break and he can give you that information now, if you require?

CROSS-EXAMINATION BY MR. GIBBS, CONTINUED:

Q All right, sir. Mr. Holmberg, what I was referring to was the statement on page 23 of the prepared evidence, which says that three separte tests were made to show that reinforcing bends can be used in the remote event of a fracture, to control the length of the fracture.

We're on the same wave length for the number of tests and what the tests were for?

WITNESS HOLMBERG:

A I believe so,and I apologize for not having this information available.

Q All right, sir.

Could I just make sure we get them in chronological order, these tests took place at separate times over a period of about a year or 18 months?

A Yes, the tests I'm referring -- these particular tests actually occurred over a shorter period of time during the past year.

Q If it's convenient then,

could you refer to them in chronological order --

A Yes.

Q -- and then go ahead and describe them in your own words?

A Yes. The first test in which crack arrestors were specifically tested, was a test conducted last July. This had a four foot arrestor and the fracture propagated and stopped at the arrestor.

The -- in -- as a result of that, and the decision to investigate arrestors further, two tests were made using a somewhat different configuration as far as the pipe was concerned. These tests were made at ambient temperature, and were made with just -- instead of having the fracture propagate in opposite directions, the notch at which the fracture initiated failure was located near one end of a somewhat shorter length of pipe.

The crack arrestors in these tests, and I might say that this was done to more effectively check crack arrestors. The crack arrestor was located only 12 feet from the origin point. The crack arrestor in one test consisted of a two foot band, and the ends were seal welded. This test proved to be effective.

Then the, I believeit was the following day a similar test was made in which a two foot crack arrestor was tested, in which the ends were not fillet welded. This arrestor also proved to be effective. These are the three crack

arrestor tests that were referred to in the testimony.

I might point out that I would like to make sure there's not a misunderstanding, and that is you asked me about the spacing of the crack arrestors this morning. In these tests, we've actually had a series of several crack arrestors incorporated in each test, so that in the event that arrest did not occur at one arrestor, we would get some information that would be of use for design purposes, and we would possibly get arrest in the next arrestor.

The tests to date, why the arrest has always occurred in the first arrestor present, so when you talk about the distance apart, there may have been some misunderstanding where we had this series of arrestors, they were in some of the tests rather closely spaced.

Q Well then sir, there were really then four tests, were there?

A Well there's since been another test, and this is a test that's been more recently made, in which it was intended to test crack arrestors, but as has occurred in so many of these tests, we've actually had problems of having the -- of being successful and having the fracture propagate.

These shear fractures propagate at slower speeds as was pointed out yesterday, and are more susceptible to termination by slight deviations in properties or conditions which we don't entirely understand. As a result, the last

test that we made, we didn't succeed in getting the fractures to propagate up to the crack arrestors.

Q Well Dr. Holmberg, or Mr. Holmberg, I asked for some notes about these tests, and perhaps I can ask you about them and see whether what I am told agrees with your view of the tests?

I'm told that in one test, the fracture when initiated, went 150 feet approximately in each direction, and then it stopped on one end at what's called an anchor flange, and at the other end it stopped at the fourth girth weld. Is that accurate?

A That is not one of the tests that I included, this arrest at the anchor could be included a crack arrestor, it performed as a crack arrestor, and actually in the pipeline industry there has been a good many instances where propagating fractures have terminated at a change in sections such as a valve or a fitting or anchor point or something of that type. So in effect, there has been some experience that it is possible to stop a propagating fracture by other means than just the toughness of the material.

Q Well, in that particular instance it stopped at the girth weld on one end and at the anchor flange on the other.

A That is right, and the stopping at the girth weld is an illustration of the difficulty we've experienced in getting these fractures to propagate in the sheer mode, to the distances that we would like to have them propagate.

Q Then, sir, there was another test where the fracture ran in each direction and in one direction it stopped of its own accord after about 80 feet, and in the other direction it stopped after about 100 feet at one of your arrestor bands.

A That's right.

Q Then in still another test as this fracture went in each direction, going in one direction it stopped or it I suppose burst the first girth weld , the first girth weld failed, and going

in the other direction the first girth weld failed, the second girth weld failed, and the fracture then by-passed the arrestor and re-initiated itself again. Is that correct?

A Yes, that is correct.

Q In the third pipe length?

A Yes, this is what I refer to as a racing test.

Q And doesn't that lead you to conclude that the arrestors really don't stop the fractures when they can come up, by-pass it, and be initiated again?

A No, very definitely not. I think it illustrates again the difficulty of making these sheer fractures propagate. Just minor deviations at a girth weld, for example, is enough to cause it to stop. Crack arrestors are being very conservative and this matter of the pipe breaking off and then a fracture re-initiating, this is something that occurs occasionally in pipeline failures. This has occurred in failures in smaller, conventional-size lines. I think this is just another example of that type of re-initiation of a fracture. This has been observed numerous times.

Q Yes. Well, is it a correct conclusion to say that the arrestor band didn't, in that circumstance, arrest the fracture?

A That's right, we did not include that as an example, as a case where we succeeded

in getting arrest at a crack arrestor. This was an additional test that was made, and the fracture arrest -- we failed to get a test on the crack arrestor because the fracture terminated before it reached the arrestor.

Q Well, is it correct then to say that in only one of the cases did you really get a test of the fracture?

A No, we have three definite tests.

Q I see, and in your interpretation every one of the three showed that an arrestor band would stop a fracture?

A Very definitely.

Q Notwithstanding that it only really stopped at an arrestor band in two of the cases.

A No, it stopped at an arrestor band in three tests.

Q I see. Well, I thought that in the first one it stopped in one direction at the girth weld and at the other direction at a flange.

A At the anchor. That was not included in the three tests that I cited.

Q All right, sir.

A You're going back to what has been referred to as the first CAGSL test.

Q But taking that one, that didn't prove anything to you about arrestor bands, unless a flange operates the same.

A Yes, to me it was significant, as I've mentioned before, to confirmed previous experience that fractures will arrest at changes in section such as flanges and so forth. We did not consider that a crack arrestor test. However, it does demonstrate that fractures can be arrested by changes in section.

Q Yes, but we can put that one aside as being no help as a fracture arrestor.

A We did not include that as one of the tests.

Q All right. Then we get the next one, I put to you where the fracture ran 80 feet in one direction and stopped of its own accord, and 100 feet in the other direction and stopped at an arrestor band.

A Yes.

Q That you interpret as being a test of the arrestor band?

A Yes.

Q Have you any way of knowing whether that fracture would have stopped there without the arrestor band?

A The calculations and studies made indicated that it would have continued to propagate.

Q I see, so that's a test that shows --

A That's what we considered

the first crack arrestor test.

Q Then there was another one that I put to you where in one direction it ran and a girth weld failed, and in the other direction it ran and the first girth weld failed and the second girth weld failed, and then it by-passed the arrestor and initiated again,

A That's right.

Q And in your interpretation does that show that an arrestor is a successful technique?

A No. We failed to get a test on an arrestor.

Q So we put that one aside. And the next test is the one you told us about where the arrestor --

A I might say that these two tests that you're referring to now took place last October, and were before this last test that you were describing.

Q And this last one is the one where the arrestors were what, 12 feet apart or 12 feet from the fracture?

A There were two separate tests. In both cases, the arrestor was approximately 12 feet from the initiating point.

Q Yes. And in those cases, the fracture stopped at the arrestor bend?

A Yes. So that makes the three tests that were referred to in the testimony.

Q Out of five?

A Out of five tests, but the first test was not designed specifically as a crack arrestor test. It did stop at this anchor flange, however. The last test was designed as a crack arrestor test, but we were not successful in making the -- in obtaining the, or getting the fracture to propagate far enough to reach the arrestor. The fracture terminated before it reached the arrestor, and this is one of the things that I think is quite important as far as the shear failures.

The industry to date,experience is that these shear type fractures do not propagate long distances. The first shear type fracture occurred I think it was in the winter of '68-69, and as far as I have been able to determine, there have been to date only six shear type failures that have been over 300 feet long, and the longest failure service, or failure in service has been in the order of a thousand feet long.

I think this again illustrates that it's difficult to make these slow running shear fractures propagate long distances, and our decision to use these crack arrestors is really being, in my opinion, very, very conservative.

Q And you're satisfied, Mr. Holmberg, on the basis of those three successes out of five tests, if I may put it that way, that the band method of fracture arresting is sufficiently proven to be relied upon?

A Yes.

Q Is that technique in use anywhere else in North America, in a natural gas pipeline?

A As far as I know, it is not, as specifically as arrestors, however the use of crack arrestors is nothing new or novel. For example, during the war when ships were breaking in two, one of the first corrective measures was the extensive use of crack arrestors. This proved to be very, very effective and is still used in spite of the development of notch tough steels that are resistant to fracture.

For example, the United States Navy has certain ships in which they have some of the toughest steels available. They do not consider it prudent to rely simply on notch toughness to arrest fractures. They consider it to be absolutely safe, it's necessary to rely on crack arrestors, and there are other cases in the oil industry, as well as other

industries, for example the aircraft industry where crack arrestors are used. It may be a new application as far as the pipeline is concerned, but it's not a new concept by any means.

Q No sir, but in the sense of experience being a part of technology in the use of this technique in a natural gas pipeline, you are incorporating a new technology?

A Yes, I would say we are incorporating a new technology to increase the safeness of the line.

Q And isn't there, Mr. Holmberg, another way that you can reduce the risk of fracture propagation, and that is by reducing the operating pressure?

A Yes, that is beneficial.

Q And was that given consideration in your design?

A This has been discussed, but we decided not to go that way.

Q Why?

A We feel the crack arrestors is a more foolproof and more reliable method than to go to lower pressures, or smaller diameter pipe.

Q The ultimate test really is that it's more economic to use fracture arrestors than it is to reduce the pressure?

A I'm not qualified to answer that.

Q Well reducing the pressure

reduces the daily throughput of the pipeline, would it not?

A Yes, I understand that.

Q Yes, and so that reduces -- it follows your --

A Yes, but where the economic balance is, I don't know.

Q I see. Mr. Holmberg, I'm told that the use of these fracture arrestor bands may introduce a risk -- a greater risk of corrosion than would be the case if you were not using the bands? Do you agree with that?

A There is a possibility of this, but it's being studied and we think we have several methods of combatting that. I personally don't think this is a serious factor.

Q Well, in existing pipeline systems, something similar to an arrest band is used when a hot tap is placed on the pipeline, is it not?

A Yes.

Q And isn't it fairly normal operating procedure in due course to cut out that reinforcing band because of the corrosion possibilities?

A I'm not sure that I understand what your question is. That is you put the band on and make the hot tap, and I don't follow you on cutting it out.

Q But at some later stage you take that out and you put in what's been called,

I think a T joint, so that you get rid of that hot tap and the reinforcing part that you put on when you made the hot tap?

A I don't personally know that that is done. I could see where there would be reasons for putting a T in rather than a hot tap connection, however.

Q For the three tests, Dr. Holmberg, whose pipe was tested in each of those three cases? Which manufacturer?

A I would have to check on that, I'm sorry. I didn't bring these particular files with me, I thought I brought every file imaginable. I had to check on the phone and get this information.

Q All right. Mr. Purcell, could we come back to you and ask you to address your mind to the steel specifications? Are you with me?

WITNESS PURCELL:

A Yes sir.

Q And is it not so, Mr. Purcell, that the metallurgical subcommittee determined the steel specifications?

A That's what I think we say in the direct evidence, yes, sir.

Q And that not one member of this panel was a member of the metallurgical subcommittee?

A The metallurgical subcommittee by definition was composed of people who

worked for the sponsoring companies of Arctic Gas.

Q Yes, and therefore --

A Mr. Holmberg did attend, I think, most all the meetings of the sub-committee, as did people in Northern Engineering, and people in Canadian Arctic Gas.

Q Yes sir, but to come back to my question, not one member of this panel is a member of the metallurgical subcommittee?

A By definition I think because they work for someone else.

Q Yes. But however, they were not a member?

A But that doesn't imply that they had no voice in the deliberations.

Q Well sir, I am coming to that. And then at the metallurgical subcommittee meetings where the manufacturers were interviewed, the only member of this panel who was in attendance at those meetings was Mr. Holmberg?

WITNESS HOLMBERG:

A Yes, that is correct.

THE COMMISSIONER: Excuse me, the mettallurgical subcommittee which decided on the specifications for the steel, consisted of metallurgists, I take it, from the members of the consortium which sponsored Arctic Gas, is that --

WITNESS HOLMBERG: That's right.

WITNESS PURCELL:

A It wasn't a hundred percent representation. They selected several.

MR. GIBBS:

Q But just to be sure, no -- it was not this design group on the witness stand that determined the steel specifications?

A Mr. Holmberg participated in the discussions and I'm sure had an influence on the specifications that were developed.

Q Yes sir, but I cannot say as I look at all eight of you, that you are the group that determined the steel specifications?

A That's right.

Q Yes. Can we talk now, Mr. Purcell, a little bit about welding? Is the girth welding which occurs in the field, a matter for the design group to take into account? Do they specifcy what's required in the girth welding?

A The development of the girth weld welding procedures is again a function of the metallurgical design sub-committee.

Q And so that sub-committee of representatives of sponsors determined what the welding techniques should be.

A Yes, and in this case I think Mr. Holmberg is the gentleman that the sub-committee appointed to lead the research, to lead the development of that work. Is that not correct?

To write the initial specifications, at any rate.

WITNESS HOLMBERG:
I was given the responsibility for preparing the welding specifications. In addition to that there was a research program put into effect, and one of the member company representatives was chairman of that research group.

And again

I attended many of their meetings but I was not a member of that group, by your definition.

Q In those meetings of the Metallurgical Sub-Committee, you were there as a guest in attendance to listen and advise.

A Could be defined as a guest. However, I was participated -- was free to participate in any way considered appropriate.

Q Now sir, if you take a piece of pipe with one or more girth welds in it, would it be accurate to say that if there is a risk of failure, the risk is greater at the weld than it is in the manufactured section of the pipe?

A Yes, I'd say that's been

the experience.

Q Yes, and to the extent that .720-inch of wall thickness is greater than .540, the risk is greater with the thicker wall surface than the thinner one.

A I don't know as I'd agree to that. I think the risk is approximately the same in both cases.

Q Well, as I understand it, sir, in girth welding the practice is to weld around the pipe and then around again, and each time the weld goes around it's called a pass.

A Yes.

Q And clearly you would agree that three-quarters of an inch pipe requires more passes than half an inch pipe.

A Yes.

Q And will you not then take the next step with me and agree that therefore three-quarters of an inch pipe girth weld is a greater risk probability or possibility than half-inch pipe girth weld?

A No.

Q I see. Why would you not agree with that?

A Because each time you make a pass on the -- in welding, you have some beneficial effect on the preceding passes, and this would be greater on a thicker wall than on a thinner wall.

Also, the area that's most susceptible to failure is actually the route pass, and this includes a greater proportion of a thin wall as compared to a thick wall.

Q Aren't girth weld failures also related to the pipe composition, what I for want of a better expression call the hardness of the pipe? Its ability to be welded.

A Yes.

Q And are you familiar, Mr. Holmberg, with recent serious problems in the girth welding of pipe by Union Gas in south-western Ontario pipe produced by Stelco?

A No, I'm not.

Q We talked a little bit about the making of steel now, and I guess it's Mr. Purcell who is the chairman of the panel who I should be talking to. In the making of the steel that you require, Mr. Purcell, are there not two, for want of another expression, two inherent problems that the pipe manufacturer has. One is in the actual making of the steel, and the other is in the rolling of it into pipe? Those are the two really basic significant operations, are they not?

WITNESS PURCELL: Yes sir, I'm sure they are. I think if you carried on this dialogue with Mr. Holmberg you'd get better informed answers, though.

Q That's assuming that that's what I want, but surely, we'll talk with Mr. Holmberg.

THE COMMISSIONER: Excuse me a moment, Mr. Gibbs. Mr. Gibbs, carry on, please.

MR. GIBBS: Q I'm right to begin with in saying that your specs call for 40-foot joints, plus or minus a small variation?

WITNESS HOLMBERG: Yes.

Q And that if I take 48-inch pipe and measure the circumference, I get 12 1/2 feet.

A I believe that's right,

Q Within a few decimal points.

THE COMMISSIONER: Excuse me, Mr. Gibbs. Do you mind just repeating that?

MR. GIBBS: Yes sir. I asked whether I was correct that their specs called for 40-foot joints, 40 feet in length.

THE COMMISSIONER: 40-foot lengths of pipe?

MR. GIBBS: Lengths of pipe, and that when you measure the circumference of a 48-inch diameter pipe the result is about 12 1/2 feet.

THE COMMISSIONER: Yes, all right, I'm on board.

MR. GIBBS: And I believe Mr. Holmberg agreed with that. So for every joint of pipe, what that steel producer has to produce is a plate of steel of consistent quality throughout, 40 feet long and 12 1/2 feet wide, and .720 of an inch thick.

A Yes.

Q And that thickness

tolerance is very narrow, is it not? You can go thicker by 10%, which would bring it to 0.79, and thinner by 5%, which would bring it down as low as 0.69.

A Yes.

Q And that plate must have no flaws.

A Steel, as well as any other product, is not absolutely free from flaws.

Q All right, but a very minor and minimal amount of flaws.

A That's right.

Q And isn't that the first test of the steel maker to be able to produce that plate?

A Yes.

Q And that's one of the difficult things.

A Yes.

Q To use a homely analogy, I'm told that it's like making icing, that lots of people can make icing but only the good chef can make superb icing.

A It can be put that way, I guess.

Q And that's the case in these steel plates.

A There is a lot of skill in making it, yes.

Q And that's really what

as at April 1973, at least, Stelco lacked in their abilitv to produce that plate, was the master chef or master brewer who could turn it out.

A I wouldn't put it quite that way. Stelco is just starting at the time to develop the ability to make the plate, they had certain limitations in their equipment at that time, they had not made a -- I believe at that time they had not made a firm decision to go ahead and make 48-- equip their mill to make 48-inch diameter pipe, so at that time they had done relatively little work as far as developing a steel for this project.

Q And of those dimensions.

A Yes, that's right.

Q And that really is a technique or ability that improves with experience as you go along.

A One of the limitations and factors that has to be considered is the physical ability of the plate mill itself to roll the plate that large.

Q Yes, and sir, since April of 1973, Stelco really hasn't had much opportunity to develop the technique of rolling that plate to your specs.

A Stelco has made the decision to put in a pipe mill that will make spiral welded pipe. This requires -- this enables them to make pipe with a narrower width of plate than a 12-foot wide -- 12 1/2 foot wide plate.

Q And have they produced any spiral weld pipe on a production -- sustained production basis of your specifications?

A I don't know of any.

Q Then the next problem in the making of the pipe is the taking of that plate and rolling it into a pipe, and welding a seam.

A Yes.

Q That's done with the plate cold?

A Yes.

Q And that requires -- that's a technique which is an acquired technique, is it not, to be able to roll that without altering the roundness so you can get a consistent roundness of pipe.

A Yes.

Q And that again is an ability or technique that comes with experience?

A Yes.

Q And would vary with the thickness of the pipe and the width of the plate?

A Yes, to some degree.

Q Now sir, is there any experience in North America, to your knowledge, in rolling pipe to your specifications twelve and a half feet wide into a round pipe which will sustain the pressures that your pipeline is going to have to sustain?

A No, there's no experience to our specifications.

There's experience in making steel to the specifications, making pipe to smaller sizes to the specifications, and I might say that in making pipe to smaller sizes, frequently a more serious problem than making it to a larger size, for example the degree of bending that is required is more severe on smaller sizes than large sizes.

So it shouldn't be interpreted that simply to make larger size pipe is necessarily more difficult.

Q Or necessarily more easy because of the thickness?

A I can conceive of situations where it could be easier.

Q The absence of experience, sir, comes back to what I talked to Mr. Purcell

about and that is that this package is a new technology?

A I don't consider it any new technology. Simply to change sizes and dimensions and specifications to a minor degree, does not, in my opinion, introduce a new technology.

Q Well, Mr. Purcell --

A There have been advances in which we're applying taking the benefit of advances in technology, and I don't think we need to apologize for that.

Q No sir, but you're proposing to put in a system, the like of which has not and does not exist in the world, are you not?

A That's right.

Q Now, Mr. Purcell, can we come back to the two 40 inch supply lines from the north that meet at Travaillant Lake? In March of this year, Mr. Purcell, the applicant produced the document called "Supplement to Applications and Exhibits Relative to Alternative 42 Inch Supply Lateral Line Size" which has been marked as Exhibit 74, and you, I presume had some input into the preparation of that document?

WITNESS PURCELL:

A Yes, we did.

Q And is it right to conclude that that was filed a year after the application was filed, that it was sometime in that year between March, 1974 and March of 1975 that you began seriously

considering 42 inch lines instead of 48? For the northern supply lines?

A Yes, sir.

Q But there was no change in the daily volumes you were to put through those two lines?

A That's correct.

Q Then what led you to conclude that you should think about 42 when from 1969 to 1974, 48 inch seemed to be appropriate?

A It was not my decision to consider 42 inch. It was made by Canadian Arctic Gas, of course.

Q So that was another part of design that the sponsor donated to you?

A Yes, as in all the other cases. They had rough information on the relative costs of transporting gas through these two sizes, that we had prepared.

Q And what you are contemplating in that alternative and described in Exhibit 74, is 42 inch outside diameter, zero decimal 63 wall thickness, operating at 1,680 feet per square inch gauge? Pounds per square inch gauge?

A Yes, sir.

Q And in the sense that I induced you to agree with me that the other package was new, had not any experience in the world, would the same apply to this? Is there experience in using 42 inch outside diameter zero decimal 63 inch wall

thickness operating at 1,680 pounds persquare inch?

A No, sir, I think not.

Q And so that is at much a new innovation in pipelining of natural gas in the world as the 48 inch was?

A In the sense that it hasn't been done before, that's correct.

Q But what that does do for you, using those 42 inch lines, is now it brings you in within your test of minimum cost of transportation much better than it did with two 48 inch pipelines?

A I think the filings show that there's a slight improvement in cost of service with the 42 inch pipeline.

THE COMMISSIONER: Excuse me, I don't understand that.

What is the advantage again?

A This is a part of the work that we did not do. It's based on some of the work we did. The cost of service, the cents per mcf cost of transporting gas was slightly reduced by the 42 inch pipe size alternative, primarily because there's a lower construction cost.

Q Now these are for the supply laterals?

A Yes, sir.

Q From Prudhoe Bay and Richards Island?

A That's correct.

MR. GIBBS: Well it's not only

because of a lower construction, it's lower capital cost too, surely?

A That's what I meant by construction cost, yes, sir.

Q Have you any idea then, Mr. Purcell, why 42 inch lines were not used in the original application?

A We've stated in the application that an overriding criterion was to delay looping as long as possible, so we put in excess capacity in the 48 inch lines, at the expense of a slight increase in the cost of service.

Q And now you are contemplating improving the cost of service by reducing the size?

A That's an alternative that's been suggested by Canadian Arctic Gas.

Q And in Exhibit 74, on page 3, the applicant says:

> "The material submitted herewith is filed so that it may be examined by the board, the Department and its inquiry at this time, so that final evaluation may be made more expeditiously should the applicant hereafter determine that it should amend its applications to reflect the changes".

Do you have any information on whether that determination has yet been made?

A No sir, to my knowledge,

that has not been made.

Q So as far as you're concerned, we're still at the 48 inch high cost of service supply lines?

A I think Canadian Arctic Gas --

MR. MARSHALL: Well I don't think that's what the witness said, Mr. Gibbs.

MR. GIBBS: No, that's what I said because I was asking the question.

A I think that CAGSL has filed this as an alternative. I don't know how heavily they weight it, I can't answer the question.

Q Could we now go back, Mr. Purcell, to page 5 of your prepared evidence? In particular, the last two of the objectives on the -- at the end of the second paragraph of page 5, and in summary, Mr. Purcell, is this not correct, that you have in fact incorporated technology which is not present day technology?

A No, Mr. Gibbs, I don't agree. I think the interpretation has to do with the confidence that we can get pipe to these specifications. Pipe seems to be the item on which we are spending our time.

We can get pipe to these specifications within the schedule for the project, within the normal lead time. We are confident that the mills can make this kind of pipe and in that sense, I don't think we're depending upon something that

may happen in the future.

Q But sir, in the sense that this package has never before been used anywhere in the world, is not that new technology?

A I think we're building -- we are building up to the 48 inch in steps, and each one of the steps involves an increase in diameter, or an increase in wall thickness, and the fact that it hasn't been done before in that combination to me is not -- does not mean that we are using new technology.

Q Then your third objective was, that the pipeline system should be an optimum design so that it could be built and operated to transport gas at the minimum unit cost?

A That is an engineering objective.

Q Yes, sir.

A And that at all times in our work, was our objective.

Q But you --

A There are other non-engineering considerations that sometimes take precedence.

Q But sir, how did you meet that objective? How did your eight people here at the table -- you were given the points of supply; you were given the daily volumes; you were given the gas composition; you were given the points of delivery and you were told what pipe sizes to use,

and you were told what specs you had to use? So what did you do to design the system?

A Given those starting points, we did our compressor station design so that we came up with the minimum unit cost of transporting the gas through that system. I think that's the primary example of continuing to use the -- continuing to follow that objective in view of what had been given to us.

Q So your design really narrows down to a compressor station.

A It's always, I'm sure, been an objective of Mr. McMullen, to build a communications system that would, along with the other things that are important to him, have a minimum cost. There is an awful lot of design that goes on after the pipe size is selected.

MR. GIBBS: Mr. Commissioner, I wonder whether my friend, Mr. Marshall, is going to produce someone who can speak to those very basic points of design, which this panel has really evidently nothing to do with?

MR. MARSHALL: We have indicated that Mr. Horte will be called as a witness, Mr. Gibbs, and there are a number of these things that he will speak on, the points of supply and delivery and so on.

MR. GIBBS: Those are all of my questions.

THE COMMISSIONER: Could I just ask you a question, Mr. Purcell?

Q Mr. Gibbs emphasized with you when he was asking you about your statement that you were not going beyond present day technology. The diameter of the pipe and the wall thickness, and the problems that that would create in manufacturing the pipe and so forth, what -- you may have said this -- but the pressure, the gas is under pressure when it is expelled from each compressor station at, I think

it was 1,650 pounds per square inch. Is that right?

WITNESS PURCELL: 1,680.

Q 1,680. Maybe you did answer this question. The conventional operating pressure of natural gas pipelines in Canada, is there any figure you can give me or are they all over the place? And whether they are or not, are any of them within the range of 1,680 pounds per square inch?

A No sir, I think they are more in the range of 700 to 1,000 pounds per square inch. I think there are several reasons for our departure that can be explained. One has to do with the fact that this pipe of this size and wall thickness has not been available for a very long time, and people have not had the chance to use it. Another factor is that the increasing the diameter and increasing the wall thickness and operating pressure gives you economics in the cost of service and the unit cost of transporting gas, but you need enormous gas volumes to get to the level before you can take advantage of it, and this is one of the first new systems that's been proposed recently where that kind of gas volume has been part of the picture.

THE COMMISSIONER: Yes. Well I think this is a good time to adjourn and I should warn the counsel and of course the panel and others that we might have to take a day off Thursday. We might not sit Thursday. I'll let you know tomorrow.

So we will adjourn to 9 A.M.

then.

(PROCEEDINGS ADJOURNED TO APRIL 16, 1975)